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FACTORS AFFECTING NATURAL GAS-FIRED ELECTRICITY GENERATION

SUMMARY

Natural gas is expected to be the fuel of choice for the foreseeable future. Most planned thermal generation in the U.S. and Canada, whether new or as a result of repowering, will be supplied by natural gas-fired combustion turbine power plants. There are a number of reasons for the switch to natural gas-fired combustion turbine generation (simple or combined cycle) and these include low capital cost, high availability, high overall plant efficiency (particularly with cogeneration), wide range in plant sizes, modular construction, low emissions and short lead times. However, despite these benefits, a utility planning natural gas-fired generation must be cautious. Forecasts of significant increases in natural gas demand raise questions - "Is there sufficient natural gas to satisfy the needs of the North American market, can it be brought to the potential customer and at what price?".

Natural gas is a fuel which is readily transportable by pipeline, there are pipelines throughout much of North America and new pipelines or upgrades of existing pipelines are proposed. Therefore, natural gas must be viewed in a North American context rather than simply a Canadian or B.C. context.

North American reserves of natural gas are sufficient for about 10 years at present rates of production. There are additional resources, both discovered and undiscovered which will be developed as markets and prices dictate. It is estimated that total discovered and undiscovered natural gas resources in the producing areas of B.C. and Alberta are sufficient for about 30 years (the life of a new combustion turbine plant) at planned rates of production. Other resources will have to come from deep reservoirs, non-producing areas, frontier areas or offshore where drilling, recovery and transportation are more expensive. In addition, tight gas reserves, coal bed methane and coal gasification provide additional resources and their prices provide upper limits on the price of natural gas. In some cases, coal bed methane can be produced at lower cost than natural gas, but generally these resources cost more. These alternatives to natural gas have not been explored extensively in B.C. at this time.

The principal new markets for natural gas are in the U.S. and 1991 will be the first year in which exports of B.C. natural gas over the Westcoast system will exceed domestic demand. With present capacities and proposed additions to pipelines, their system can

handle the forecast capacities, but there will be more demand for firm gas to serve new generation from IPPs and self-generators in the the Lower Mainland/Vancouver Island and Northwest Washington. Sales of B.C. natural gas for 1990/91 and forecast sales for 2002/03 are summarized in Table 1. The present capacities of the pipelines are also noted in Table 1.

Westcoast Energy forecasts that natural gas demand for the domestic and export markets will increase by 86% over the 12 years commencing 1990/91 from a base of 455PJ/a. Much of the increased demand will be for power generation. It is expected that new combustion turbine plants proposed for northwest Washington and southwest B.C. will cause natural gas demand to exceed capacity more frequently during the winter months resulting in less valley and interruptible natural gas being available, despite proposed increases in pipeline capacity. New generating capacity from the U.S. plants is expected to be 812 MW, with an additional 282 MW in the Lower Mainland and on Vancouver Island and 352 MW in the B.C. Interior. Total natural gas consumption by these plants is estimated to be 70.2 PJ/a (includes supplementary natural gas use by wood-fired cogeneration plants) in southwest B.C. and northwest Washington with an additional 14 PJ/a by plants in the B.C. Interior. These estimates agree closely with those of Westcoast Energy. To ensure the availability of natural gas for generation during winter peak periods, it is expected that firm contracts will be necessary. The incremental cost of firm natural gas over interruptible natural gas will significantly increase the price of fuel for power generation. Today's difference is $2.32/GJ versus $1.30/GJ.

Natural gas prices will increase as less resources are available to serve the above loads and the increased prices will stimulate exploration and development of new natural gas resources. Therefore, there is a potential time lag between higher prices and the availability of additional resources.

Natural gas price forecasting is difficult and has been thrown into disrepute by the erroneously high forecasts of the early 1980s. These forecasts failed to consider basic processes which affect supply and cost -

1. Proven reserves expand as prices increase.
2. Coal bed methane exploration and development is being subsidized in the U.S., increasing the supply of methane which is substituted for natural gas.
3. The present recession has decreased the demand for natural gas.

Table 1 Sales of B.C. Natural Gas (PJ/a)

	1990/91	2002/03
Domestic	245	362
Other Canadian Sales	34	103
U.S.:		
Pacific Northwest	148	225
Other Regions	28	155
Capacity to Huntingdon	582	713[1]
Capacity from Huntingdon to the U.S.	313	
Capacity to the Lower Mainland/ Vancouver Island	269	

[1] Includes additions to 1996.

4. A mild winter has reduced the demand for natural gas over the high demand period.

5. The cost of extraction has fallen as productivity in manufacturing which supplies the natural gas industry has increased, thereby reducing the cost of machinery and consummables.

6. Improvements in exploration and production techniques have increased the success ratio for new wells.

7. Deregulation has improved efficiency in the market place.

Therefore, uncertainty is the key word in evaluating the course of future natural gas price increases. The increases are expected to be caused mainly by increases in the wellhead price; Westcoast Energy is actually forecasting a decrease in the real cost for delivery of natural gas to the Lower Mainland.

An Examination of a number of wellhead price forecasts (Table 2) indicates a wide range of rates of increase - from 3.3%/a to 10.3%/a (real). The two lowest forecasts are from B.C. As previously noted, wellhead forecasts are tempered by forecasts of no real increases (taxes excluded) and even decreases in the processing and delivery costs of natural gas. The proportion of wellhead price to processing and delivery cost for firm natural gas is approximately 40:60 at present. Therefore, neglecting the very high escalation forecast, the real price increase for firm, delivered natural gas to a large industrial customer on the Lower Mainland is expected to be 1.3-2.3%/a, which is considerably higher than the estimate of less than 0.7% forecast by Confer for a blended (all sectors included) price increase. In any case, natural gas price escalation will begin slowly at a fraction of a percent per annum, but increase in the mid-1990s as new markets are introduced in the eastern U.S., as utilities commence repowering and as new plants commence operation with new combustion turbines. Although it is forecast by Westcoast Energy that there should be no significant change in the quantity of interruptible natural gas available, the nature of power generation is going through changes which will make this assumption less important. As thermal generation becomes more important, firm natural gas will be required both to meet electricity demand at peak periods and to meet the requirements of IPPs and self-generators to base load their plants. The result will be an increasing emphasis on firm natural gas contracts at higher prices. Therefore, the effective annual increase in wellhead price over 19 years will range from 5.0-7.1% if one allows for wellhead price increases and the transition from valley gas to firm gas.

Table 2 Natural Gas Price Forecasts[1]

(1990 Can.$/GJ)

Source	1991	1992	2000	2010	2012	Rate (%)
National Energy Board	1.26				4.00	5.7
Confer	1.37			2.55		3.3
MEMPR[2]	1.24			2.30		3.3
B.C. Gas	1.28			3.41		5.3
Alberta Natural Gas	1.28			2.54		3.7
CERI		1.60			4.30	5.1
Gas Research Instit.[3]	1.81			5.02		5.5
Enron[3]	1.88		4.54			10.3
DRI[3]	1.49			5.07		6.7

[1] Reference cases.

[2] Includes some non-firm natural gas.

[3] From studies of U.S. natural gas Prices expressed in Canadian dollars.

EPRI forecasts that there are approxiamtely 33 years of natural gas resources in the U.S. at a wellhead price of less than \$3.25/GJ (1990 Can.\$) based on an average rate of production of 18 Tcf/a (510 Gm^3/a) which is expected to be exceeded in about the year 2000 (Enron study). This indicates that \$3.25/GJ is the upper limit for the natural gas price in the U.S. and that the price in B.C. would have to be considerably lower to allow for additional transportation costs into the U.S. market. However, it is also evident that it would require significant increases in the wellhead price of natural gas to encourage the development of all of these resources.

Large expenditures will be required in looping pipelines, increasing pressures and installing new feeder pipelines on the Westcoast system to take advantage of the additional market opportunities. Additional pipelines will also be required in the U.S., particularly to provide access to the large California market. These facilities are either planned or under construction.

Close coordination will be required between pipeline operations and utility operations as large combustion turbine plants are installed for power generation. These plants have rapid start-up and shut-down which impose very difficult operating conditions on the pumping stations supplying the natural gas.

In general, the natural gas industry in the U.S. and Canada has little experience in dealing with utilities. In 1988, 88 percent of natural gas-fired electricity generation was concentrated in only 6 states in the U.S. The natural gas industry is not experienced with increasing its supply quickly to meet growing demand. By contrast, the electric utility industry has built up a capacity margin and coordination among utilities through NERC. There is no analagous concern for reliability in the natural gas industry and less integration among the players on the supply side - production and processing, transmission and distribution.

B.C. Hydro continues to review strategies for securing natural gas supplies for Burrard Thermal Plant. If B.C. Hydro plans to use Burrard extensively in the future, absorb fuel price risk or install significant combustion turbine capacity in the event of a shortfall in other resources, B.C. Hydro should continue to examine all methods of reducing the risk of large fuel price increases.

Despite the need for caution, natural gas-fired generation provides a viable alternative to hydroelectric generation and can be used to complement a predominantly hydroelectric system.

FACTORS AFFECTING NATURAL GAS-FIRED ELECTRICITY GENERATION

1.0 Introduction

Natural gas is becoming the fuel of choice in many sectors of the economy. The renewed interest in natural gas as a utility fuel is a result of the following factors:

1. Short lead time for combustion turbine plant construction.
2. Low plant capital cost.
3. Unit sizes which can be small to allow for small increments in capacity.
4. There is a potential for high thermal efficiency with combustion turbines.
5. Natural gas can be delivered easily to generating plants close to load centres.
6. The use of natural gas causes fewer environmental impacts than coal or oil.
7. The price of natural gas is relatively low and it is not forecast to increase markedly in the near future.

These factors reflect the utility concern about uncertainty in load growth and the need to meet environmental regulations. Despite these factors, past experience is causing utilities to approach high penetration of natural gas-fired units with caution. There are fears of natural gas price exposure and curtailments during cold weather. These fears result from the coincidence of high natural gas demand for heating on cold winter days when demand is also high for electricity. The lack of sufficient pipeline capacity during these periods causes pipeline companies to curtail deliveries to utilities. High electrical load growth in many areas where the economy is expanding also coincides with increased demand for natural gas for industrial processes in these areas.

Natural gas demand in the U.S. is becoming an increasingly important factor in determining the availability and price of natural gas in Canada. In 1992, Westcoast Energy forecasts that exports of natural gas over their system will surpass domestic demand[1].

Utilities in the U.S. are concerned about the reserves of natural gas, availability of processing and pipeline capacity and environmental legislation which would restrict the use of oil. Independent Power Producers (IPPs) and self-generators who use natural gas, require firm and stable natural gas prices over the life of a project to assess its viability and utilities are becoming increasingly dependent on IPPs and self-generators for electricity.

Industrial natural gas consumption is approximately 1.4 times utility natural gas consumption in the U.S. Therefore, industry is an important contributor to natural gas demand. However, electric utility fuel switching capability is 70% larger than industrial capability in the important markets outside the natural gas producing areas and utilities are expected to provide the major growth opportunuity for natural gas marketing. This development applies to B.C. natural gas as well as other sources of natural gas in North America.

In B.C. as elsewhere, we must keep in mind that the supply and price of natural gas is affected not only by the reserves of natural gas, but also by the processing and transportation capability. Natural gas-fired power plants constructed by IPPs and self- generators in B.C. and IPPs, self-generators and utilities in Washington could have a moderate impact on the availability and price of natural gas. However, the market for natural gas is a North American one and for B.C. gas it is particularly a Pacific Northwest one, but potentially governed by demand in California and the ability to transport natural gas to California.

Environmental legislation could markedly increase the demand on available natural gas and cause a rapid escalation in price.

This report examines the demand for natural gas, the risks facing a utility which plans to develop natural gas-fired electricity generation and it identifies actions which could be taken to mitigate those risks. The risks include the availability of natural gas resources and infrastructure, as well as fuel price escalation. The report makes recommendations for further work which should be undertaken to ensure that this option for power generation remains available to B.C. Hydro.

2.0 Natural Gas Reserves and Resources

2.1 Introduction

Natural gas is a non-renewable resource. Therefore, there has been concern that the cost of exploration and devlopment will gradually become too high or that the supply will be effectively exhausted. However, the recent deliverability surplus and "gas bubble" have tended to reduce the level of concern and increase the demand for natural gas.

Natural gas reserves are summarized in Table 2-1[2]. The definition of reserves is dependent in part on the cost for discovery of the natural gas through exploration and drilling and in part on the marketability of that natural gas based on demand and the presence of suitable infrastructure. The infrastructure is necessary to transport the natural gas to market and sufficient supplies must be found to economically justify that infrastructure.

Other unconventional reserves include coal bed methane, tight gas, shale gas, geopressurized methane and methane clathrates.

2.2 World Reserves and Resources

World proved conventional reserves of natural gas (Table 2-1) are 4825 Tcf (137 Tm^3) and world additional potential for natural gas is estimated to be 4980 Tcf (141 Tm^3)[2]. Most of the reserves and potential are in the USSR and the Middle East. World-wide reserves of natural gas are not expected to significantly affect the demand or price of natural gas in North America. U.S. reserves are larger than those in Canada, but the production rate is considerably higher. There are large reserves of natural gas in B.C., as well as the potential for the discovery of new resources.

Natural gas is transported overseas as liquefied natural gas (LNG). There is 3.2 Tcf (91 Gm^3) of liquefaction capacity in the world and 65% of that capacity is split between Algeria and Indonesia[2]. The cost of new liquefaction facilities makes it difficult for other countries to enter the market. Therefore, it expected that additional liquefaction capacity will come mainly from additions to existing facilities.

It is forecast that the use of LNG and synthetic natural gas (SNG) in the U.S. will increase from 0.2 Tcf (5.7 Gm^3) today to 0.8 Tcf (22.7 Gm^3) by the year 2000[3]. The increased supply would come from greater use of U.S. facilities and more imports from Algeria and Nigeria.

Table 2-1 Reserves and Resources of Natural Gas

	Production		Reserves		Resource Potential[1]	
	(Tcf)	(PJ)	(Tcf)	(PJ)	(Tcf)	(PJ)
World	-	-	4825	5125623	4980	5290280
U.S.	17	18059	159	168907	770[2]	817975[2]
Canada:			96.6	102619	209	222022
Alberta	3.4	3612	52.5	55771	70	74361
B.C.	.41	436	7.5[3]	7967[3]	34.6[4]	36756[4]

1. Includes discovered and undiscovered potential natural gas resources, but does not include reserves or previous production.

2. Does not include 259 Tcf of unconventional natural gas resources, tight gas or coal bed methane, but does include 129 Tcf of conventional resources in Alaska.

3. Of these reserves approximately 2.8 Tcf are in shut-in wells unconnected to the feeder systems[5].

4. For Northeast B.C. only. There is potential for undiscovered natural gas resources in other parts of the province.

Methane clathrates are an unconventional source of methane. Methane clathrates are ice-like compounds in which methane and other gases are "caged" by water molecules[4]. Methane clathrates are found in permafrost and ocean sediments where they occur in a variety of specific environments apparently limited only by the availability of a source of methane. The resource is large, estimated to be 80,000,000 PJ, but it is widely dispersed. There are numerous potential methods for recovery of clathrates, but a combination of depressurization and hot water injection appears to be the most promising. There are numerous other problems in recovering this resource such that recovery will not be technically or economically feasible in the foreseeable future.

Similarly, the natural gas resource as shale gas is small, but locally significant[4]. It will not be economic to recover it in the foreseeable future because of the low permeability of the host rocks. Many of these shale resources are found in the eastern U.S.

Geopressurized natural gas resources are small and localized in a few areas including the Gulf States of the U.S. These resources could be exploited for their geothermal potential with the natural gas as a by-product. The geopressurized natural gas resources have not been thoroughly assessed as a combination geothermal/natural gas resource[4].

Tight gas and coal bed methane resources are described in more detail later in this report because a great deal of exploration has been initiated in the U.S. to develop these resources. Little work has been done in Canada.

2.3 Canada Reserves and Resources

Natural gas reserves in British Columbia are concentrated in the northeastern part of the province, between Kakwa Park and the Yukon border (Figure 2-1). Most of the reserves are concentrated in a relatively small area between the Peace and Fort Nelson rivers.

The use of natural gas in Canada began in earnest in the mid-1950's[5]. Almost all of the natural gas reserves in Canada are found in Western Canada. However, there is potential for significant discoveries of natural gas off the east coast and in the far north. In 1989, B.C. and Alberta each had approximately 20 years reserves at current rates of production[6]. However, reserves had dropped from 38 years (for B.C.) in 1983. The ultimate natural gas potential for northeast B.C. is estimated to be 42 Tcf (1274 Gm^3), including reserves and resources[7].

Since the mid-1950s, and in addition to a modest contribution before that period, cumulative production in B.C. has been 15.2 Tcf (430 Gm^3)[7]. Proven reserves are 7.5 Tcf (212 Gm^3) and annual

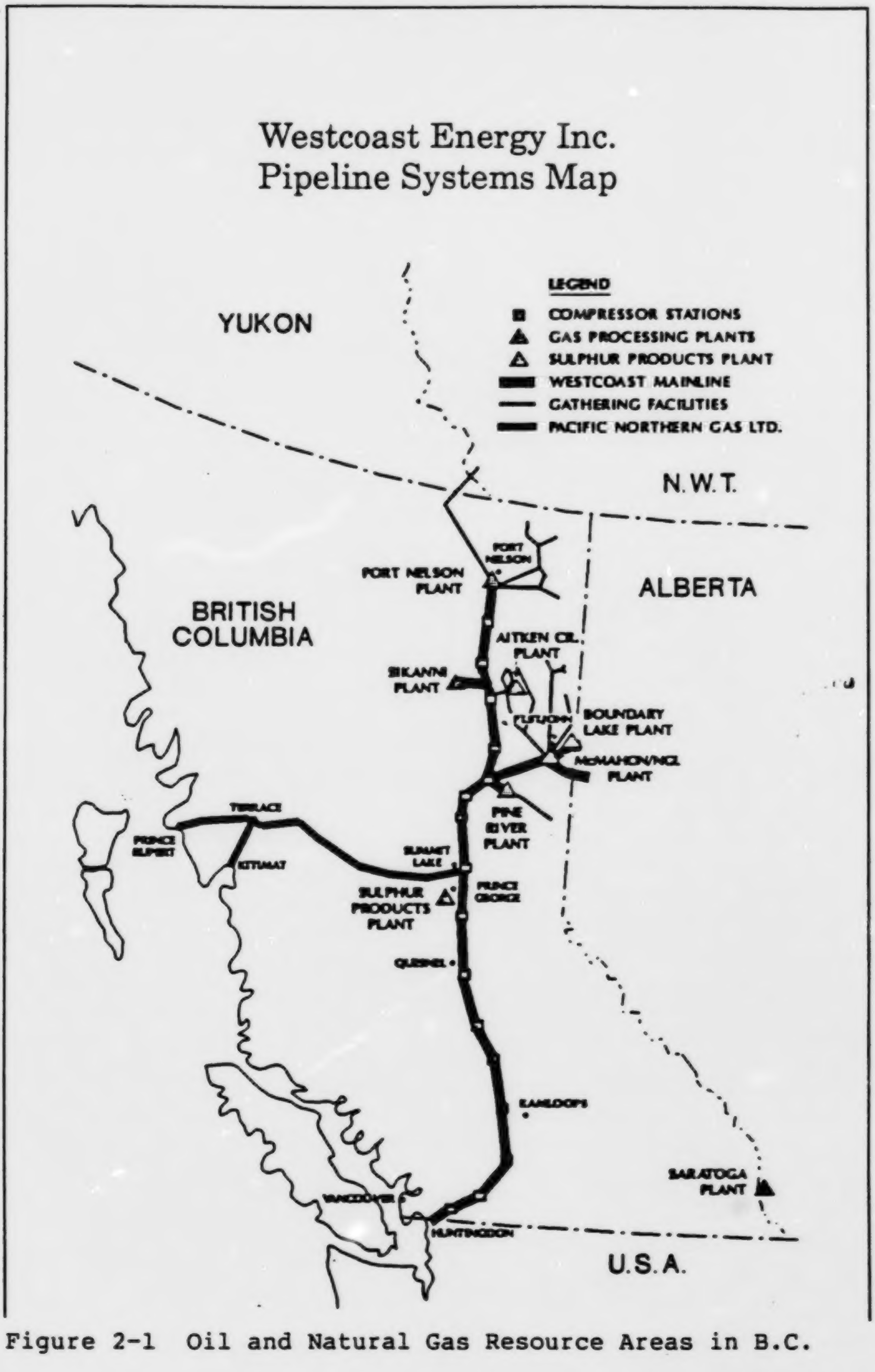
Westcoast Energy Inc.
Pipeline Systems Map
LEGEND
■ COMPRESSOR STATIONS
▲ GAS PROCESSING PLANTS
△ SULPHUR PRODUCTS PLANT
WESTCOAST MAINLINE
GATHERING FACILITIES
PACIFIC NORTHERN GAS LTD.
YUKON
N.W.T.
BRITISH COLUMBIA
ALBERTA
PORT NELSON
PORT NELSON PLANT
AITKEN CR. PLANT
SIKANNI PLANT
FT.ST.JOHN
BOUNDARY LAKE PLANT
McMAHON/NGL PLANT
PINE RIVER PLANT
TERRACE
PRINCE RUPERT
KITIMAT
SUMMIT LAKE
PRINCE GEORGE
SULPHUR PRODUCTS PLANT
QUESNEL
KAMLOOPS
VANCOUVER
HUNTINGDON
SARATOGA PLANT
U.S.A.

Figure 2-1 Oil and Natural Gas Resource Areas in B.C.

production is 0.41 Tcf (11.6 Gm^3). Therefore, present reserves are sufficient for 18 years at the current rate of production. Proved recoverable reserves accessible to Westcoast Energy's processing plants are 6.3 Tcf (178.4 Gm^3), of which 52% are at producing wells and the remainder is shut-in[1]. Undiscovered resources accessible to their processing plants are estimated to be 22.3 Tcf (632 Gm^3)[8].

There is considerable potential for coal bed methane to supplement natural gas reserves in Alberta, B.C., Nova Scotia and possibly elsewhere in Canada, but there has been little exploration for this resource because of the surplus of conventional natural gas in western Canada. Coal bed methane is a valuable resource which should be developed, particularly in Nova Scotia where there are presently no supplies of conventional natural gas.

2.4 United States Reserves and Resources

The United States had an estimated 1885 Tcf of recoverable natural gas resources when development of these resources began in earnest in the 1950s[3,9]. Thusfar, 697 Tcf (19.7 Tm^3) of these resources have been used, 159 Tcf (4.50 Tm^3) are in reserve status and production is about 17 Tcf/a (481 Gm^3)[3]. The level of proven reserves in the U.S. has remained relatively constant at about 10 years supply since the early 1980s. It is estimated that there are another 641 Tcf (18.2 Tm^3) of conventional resources and 259 Tcf (7.34 Tm^3) of nonconventional resources in the Lower 48 States and 129 Tcf (3.65 Tm^3) of resources in Alaska[9]. At the current rate of production, these resources could last for 70 years, but the cost of production and transportation would increase markedly as more expensive and remote resources are exploited. While U.S. demand for natural gas has increased 2% since 1989, natural gas reserves have increased 8%-9%[10], thus maintaining an oversupply.

In the U.S., the Gas Research Institute estimates that there are 90 Tcf (2.55 Tm^3) of gas recoverable from coal seams which is 10 to 23% of the estimated total resource[11]. These resources are concentrated in the south central and southeastern U.S. Reserves of coal bed methane in the U.S. were 5.1 Tcf (144 Gm^3) in 1990, an increase of 1.4 Tcf (39.6 Gm^3) from the previous year, while production doubled to 624 MMcf/d (17.6 Mm^3)[10]. For comparison, the total resource of tight gas is estimated to be 622 Tcf (17.6 Tm^3); there is no estimate of recoverable tight gas resources because the resource is not well known. The tight gas resources are concentrated in a north-south belt through the central U.S., in the south and in the northeast. The deadline for spudding qualifying coal bed methane and tight gas wells is 31 December, 1992.

2.5 Discussion

For North America, potential natural gas resources are in excess of 1300 Tcf (36.8 Tm^3) if unconventional resources are included[9]. These include 695 Tcf (19.7 Tm^3) of potential, conventional natural gas resources. The bulk of North America's proved reserves of 285 Tcf (8.1 Tm^3) of conventional natural gas and coal bed methane are already developed.

B.C. presently has 18 years reserves at current rates of production. To ensure that reserves in B.C. are available, a supplier dedicates reserves or warrants that he will manage reserves to fulfill his long term contracts. Recently, the provincial government changed the rules governing exports to allow for contract terms as long as 15 years with proven reserves of only 1/2 of the contracted amount. The assumption is that the supplier will be able to find additional new reserves to fulfill the contract.

Much of the new reserves of natural gas in Canada will come from deep drilling or from frontier areas. New natural gas reserves have been discovered and with fewer dry holes as a result of improved geologic, geochemical and geophysical exploration. Reserves from deep drilling have become accessible because of the development of high temperature drilling muds and special cements for more frequent lost circulation conditions and unstable well bores, special bits for harder formations with slower penetration rates and computer hardware and software to improve penetration rates and reduce lost holes.

The natural gas suppliers differ in size depending on their respective reserves. Some sales are arranged through the larger supply companies, an aggregator or a broker. The smaller companies tend to use aggregators or brokers. In B.C., gathering from the suppliers, processing and transportation is done by Westcoast Energy Inc.

Since 1980, natural gas prices have been too low to justify further exploration and reserves have been derived from extensions to existing fields. In fact, for more than 20 years, much of the new additions to U.S. reserves have been "soft" additions in the form of adjustments to reserves as opposed to "hard" reserves which result from drilling in new fields or extensions to fields. Without these "soft" additions, U.S. reserves would have declined over the period rather than remaining fairly steady[12].

The U.S. market will account for much of the increased demand for Canadian natural gas. The National Energy Board expects that natural gas exports to the U.S. will increase from 1500 PJ in 1992 to peak at 2400 PJ in 2007 and fall back slightly after that date[13].

A factor affecting U.S. reserves of natural gas and the potential to increase those reserves as demand dictates is the availability of drill rigs. The number of drill rigs potentially available in the U.S. for drilling oil or gas wells has been constantly declining from 5,644 in 1982 to 2,251 in the summer of 1992[14]. Much of this decline has been from the retiring of rigs and most have been permanently demobilized by dismantling them for spare parts. Of the 2,251 available rigs only 1,485 are operating and many of these are drilling for coal bed methane and tight gas. Once these programs are finished there will be little work for these rigs. The number of available rigs is expected to decrease further which will reduce the capability to drill natural gas wells as reserves decline, unless natural gas prices increase to pay for new equipment.

3.0 Prices for Natural Gas

3.1 Introduction

There is an interdependency between natural gas prices and reserves. An analysis of nearly 50 published forecasts of natural gas supply, demand and price indicates that most base cases assume adequate supply, modest demand and low price increases[12]. Therefore, alternative scenarios which assume some disruption of the base case assumptions, by necessity, must result in higher prices. Higher prices are also the ultimate outcome of sustained low prices because reserves become depleted due to a lack of exploration and development.

Ultimately, the price of natural gas is dependent on the type of contract between the supplier/transporter and the customer. Natural gas prices consist of a wellhead or commodity price as well as gathering, processing, transmission and distribution costs plus a load factor adjustment and taxes. Application of these price components result in a number of different contracts which are available for the purchase of natural gas. Each of these price components other than taxes can be adjusted to suit the conditions of the purchase contract. The price of natural gas in B.C. currently consists of approximately 60% wellhead and 40% other costs (for large industrial customers in the Lower Mainland, excluding taxes). The wellhead price tends to be volatile, whereas the other costs tend to increase at a consistent rate.

3.2 Wellhead Price of Natural Gas

Natural gas prices are determined by North American market conditions which are dominated by U.S. production and demand. The wellhead price of natural gas in B.C. is further influenced by the price of natural gas in Alberta because of the much larger reserves there. B.C. producer prices are usually higher than those in Alberta because there is no load factor correction in Alberta, costs can be written off more quickly there, B.C. producing areas are more remote and B.C. wells are commonly deeper[5]. The wellhead price of natural gas must cover the cost of exploration, development and well operation and compensate for the inherent risk in exploring for a hidden natural resource.

The cost of finding and developing new natural gas reserves has decreased markedly since the early 1980s. For example, drilling costs have decreased by 50% which has helped to maintain profitability for producers despite low natural gas prices[15]. Typically, well operation adds 5 to 10 cents/GJ[16].

The demand for natural gas is not expected to outstrip the supply before the year 2000[17]. There are several reasons for the surplus production. Many producers must continue to produce at a constant rate because there may be other producers pumping from the same pool. Water inflow or subsidence can adversely affect the well over time; a shut-down could result in much of the resource being unrecoverable later. Many producers also have financing problems and they require the cash flow from natural gas sales despite the low prices.

The present low prices for natural gas which are forecast to continue for some time do not stimulate the discovery of new reserves. This fact should create shortages and the market system, if left untouched, should act to increase prices as demand for the dwindling reserves increases. The increase in prices should stimulate exploration, but there could be a period of significantly higher prices before the market is back in balance.

The deregulation of the producing sector of the natural gas industry has resulted in a spectacular decrease in wellhead prices. However, the transmission and distribution of natural gas remains regulated and costs have not declined in this sector. It is expected that competition among pipelines serving some areas of high growth in demand will produce pressures to compete and thus lower prices.

3.3 Canadian Natural Gas Prices

The National Energy Board has forecast (base forecast) that natural gas prices will rise from $1.40/GJ to $4.20/GJ in 2012[13]. This is an annual increase of about 5.7%/a which seems extraordinarily high and well outside the range of other Canadian forecasters, but within the range of U.S. forecasters.

Based on the Confer study, the average retail price of firm natural gas is expected to increase from approximately $3.76/GJ today to $4.37/GJ in 2010[7,16]. These prices are based on the prices and costs listed in Table 3-1. The rate of increase in the price of firm natural gas is estimated to be about 0.7%/a (real, delivered) or 3.3% (real, on the wellhead price) over the 19 year period from 1991 to 2010.

Other studies by the B.C. Ministry of Energy, Mines and Petroleum Resources (MEMPR), the Canadian Energy Research Institute (CERI), B.C. Gas and Alberta Natural Gas forecast wellhead natural gas price increases if 3.3%, 5.1%, 5.3% and 3.7% respectively over 20 years.

Table 3-1 Retail Price of Natural Gas in the Lower Mainland[1]

(1990 Can.$/GJ)

	1991	2010
B.C. Average Wellhead Price	1.37[2]	2.55
Wescoast Energy Firm Tolls	0.84	0.77
Gathering and Processing	(0.44)	(0.40)
Transportation	(0.21)	(0.19)
Load Factor Adjustment	(0.19)	(0.18)
B.C. Gas Firm Toll	1.55	1.05
	------	------
Total	3.76[3]	4.37[4]

1 Based on cost estimates from a B.C. Hydro memo from J.J. Gibbon to Frank Power Dated 9 July, 1991.

2 These prices differ from those based on a U.S. plant gate price in 1990 U.S.$ of $1.70/Mcf in 1990 increasing to $2.75/Mcf in 2010. The above prices would result in an estimate of $1.46/GJ (1990 Can.$) rather than the actual price of $1.37/GJ.

3 The comparable prices for large industrial customers are $2.22/GJ and $2.60/GJ for small industrial customers.

4 The increase in delivered cost of natural gas is estimated to be less than 0.8%/a (real) over the 19 year period based on the Confer estimates.

3.4 United States Natural Gas Prices

There have been numerous forecasts of natural gas price increases in the U.S. In the winter of 1991/92, it is forecast that natural gas prices will rise to \$1.75/MMBtu (U.S.\$) or \$1.88/GJ (Can.\$), falling to \$1.20/MMBtu (U.S.\$) or \$1.30/GJ (Can.\$) in the following summer[18]. Ms Carol Freedenthal(1991), of Jofree Corporation, forecasts that prices will increase by 4%/a (real) between 1994 and 1996.

Mr. Daniel Dreyfus of the Gas Research Institute forecasts that the wellhead price of natural gas in the United States will rise from \$1.68/MMBtu (U.S.\$) or 1.81/GJ (Can.\$) today to \$4.50/MMBtu (U.S.\$) or \$5.02/GJ (Can.\$) by 2010, an annual increase of 5.5% real over 20 years[19]. Data Resources International (DRI) has forecast an increase in the price of natural gas from \$1.38/MMBtu or \$1.49/GJ (Can.\$) in 1991 to \$4.54/MMBtu or \$5.07/GJ (Can.\$) in 2010, an annual increase of 6.7% real over 20 years (1991\$)[9].

Enron forecasts that in 1992, U.S. wellhead prices for crude oil will be \$20.50/bbl (U.S.\$) and natural gas will be \$1.92/MMBtu (U.S.\$) or \$2.07/GJ (Can.\$)[3,20]. The demand for natural gas in the U.S. is expected to be strong to the year 2000 over a large range of oil prices (\$20.50 to \$29.80/bbl in 1990 U.S.\$) and even at high natural gas prices of \$4.07/MMBtu (in 1990 U.S.\$) or \$4.54/GJ (Can.\$) which are forecast for the year 2000[3].

Variable costs for production of natural gas suggest the theoretical bottom for prices, \$0.60/Mcf (U.S.\$) or \$21.18/10^3m^3 (Can.\$)[21]. Ellis (1991) forecasts that the average real price increase through 1995 will be 10%/a (7.7%/a real over 5 years) reaching a real price of \$2.10/Mcf (U.S.\$) or \$74.15/10^3m^3 (Can.\$) from a current average level of \$1.45/Mcf (U.S.\$) or \$51.20/10^3m^3 (Can.\$). This is much higher than other forecasts because the author believes that new finds will come from smaller fields with lower reserves. Ellis (1991) believes that the gas "bubble" will burst in 2 to 3 years.

Natural gas prices in the U.S. have been deregulated since 1983 and the gas futures market was initiated in 1990[9]. These factors have had a profound effect on the price of natural gas, lowering natural gas prices and dampening price variations. From the end of deregulation, the spot market as a percentage of natural gas sales continued to increase until 1988. Since that time the trend in the U.S. has been to increase the number of medium to long term contracts (1 to 15 years). The natural gas futures market is used as an indicator of market conditions and also tends to dampen price variations.

If we ignore for the present, the specific environmental advantages of natural gas, the upper limit on the price of natural gas is ultimately set by the cost of alternatives . The cost of coal bed methane is presently more economical than natural gas in the U.S. because of Section 29 of the Crude Oil Windfall Profits Tax Act which was passed in the U.S. Congress in 1980 and which is not scheduled to end until 2002, but the wells to tap the resources must be developed by the end of 1992 (the 1992 date resulted from a recent extension of an earlier deadline). This act gives tax benefits to coal bed methane and to a lesser extent tight sands gas which might otherwise be uneconomic to extract. A producer of coal bed methane who has ensured that his wells are qualified, received \$2.47/MMBtu (U.S.\$) or \$2.66/GJ (Can.\$) in 1990 and \$2.17/MMBtu (U.S.\$) or \$2.34/GJ (Can.\$)in 1991[6,11,17]. The price received by a developer for coal seam gas in New Mexico, which is a major producer in the U.S., is \$0.80 - \$1.00/MMBtu (U.S.\$) or \$0.86 - \$1.08/GJ (Can.\$) plus a tax credit of approximately \$0.92/MMBtu (U.S.\$)or \$0.99/GJ (Can.\$). Production costs in New Mexico can be as low as \$0.40 - \$0.50/MMBtu (U.S.\$)or \$0.43 - \$0.56/GJ (Can.\$)[17]. This compares with spot prices for natural gas in the southern and central U.S. which have averaged \$1.30/MMBtu (U.S.\$) or \$1.40/GJ (Can.\$) over the last several years and fell below that value in 1991. Clearly, the coal bed methane price levels are well above the present selling price of natural gas which has resulted in large drilling programs for coal bed methane. U.S. gas production from coal seam wells doubled in 1990. As many as one third of all gas wells drilled in the U.S. in 1990 were drilled to explore for coal bed methane or tight gas. Companies with shut-in natural gas wells have complained that there is no logic in subsidizing these uneconomic gas resources while shutting in conventional gas wells. As well as these problems, coal bed methane recovery can adversely affect the future mineability of the coal.

Tight sands are also subject to the benefits of the Crude Oil Windfall Profits tax Act, but the subsidy is less, \$0.52/MMBtu (U.S.) or \$0.56/GJ (Can.\$) compared with \$0.87/MMBtu (U.S.) or \$0.93/GJ (Can.\$) for coal bed methane in 1990[11]. The coal bed methane subsidy is adjusted annually for inflation, whereas the tight sands subsidy is not.

As these new discoveries come on stream in the U.S., they are expected to be adequate to supply all of the incremental natural gas demand in the U.S. for this decade. As a result, many natural gas wells in the U.S. have been shut-in because of the low prices. However, many previously operating wells cannot be shut-in because this action would be detrimental to the overall recovery of the resource from these natural gas fields. The result is a glut of natural gas and methane on the market. Coal bed methane and tight sands gas added approximately 885 MMcf/d (25.1 Mm^3/d) to pipeline gas in the U.S. in 1990 and conventional production of natural gas fell by 623 MMcf/d (17.6 Mm^3/d)[11].

One question which might be asked is, "Does Section 29 contravene the Free Trade Agreement?". The answer appears to be yes, but it is probable that Canada has other subsidies and it does not want to press the U.S. on this issue for fear of retaliation.

Figure 3-1 illustrates the estimated cost (in 1990 U.S.$) of extracting reserves based on the type of reserve. These estimates give an indication of the competitive value of Canadian natural gas[22].

Another factor which has tended to reduce natural gas prices in the U.S. is the removal by the Government of Canada of barriers to exports. There are several pipeline projects, underway or planned, whereby natural gas exports to the U.S. could increase to 3.0 Tcf/a (85 Gm^3/a) by 1995. However, it is more likely that exports will be 2.0-2.5 Tcf/a (57-71 Gm^3/a) by that time[6]. Increased exports result from two advantages which Canadian producers have over U.S. producers:

1. Larger reserves relative to consumption.
2. A willingness on the part of Canadian suppliers to enter into long term contracts, but this could potentially backfire if the reserves are not found to fulfill contracts.

Alberta's Energy Minister has threatened to refuse removal permits for Alberta gas sold to California customers if prices are too low. However, this threat was not taken seriously[23]. In the 90s it is expected that the North American natural gas market will move from the spot market to longer term, full service contracts.

Market adjustments will be made as a result of improved pipeline access. Canadian natural gas is likely to replace U.S. natural gas in the north central and northeastern U.S., while low-priced U.S. natural gas from Texas is displacing Mexican natural gas in northern Mexican markets.

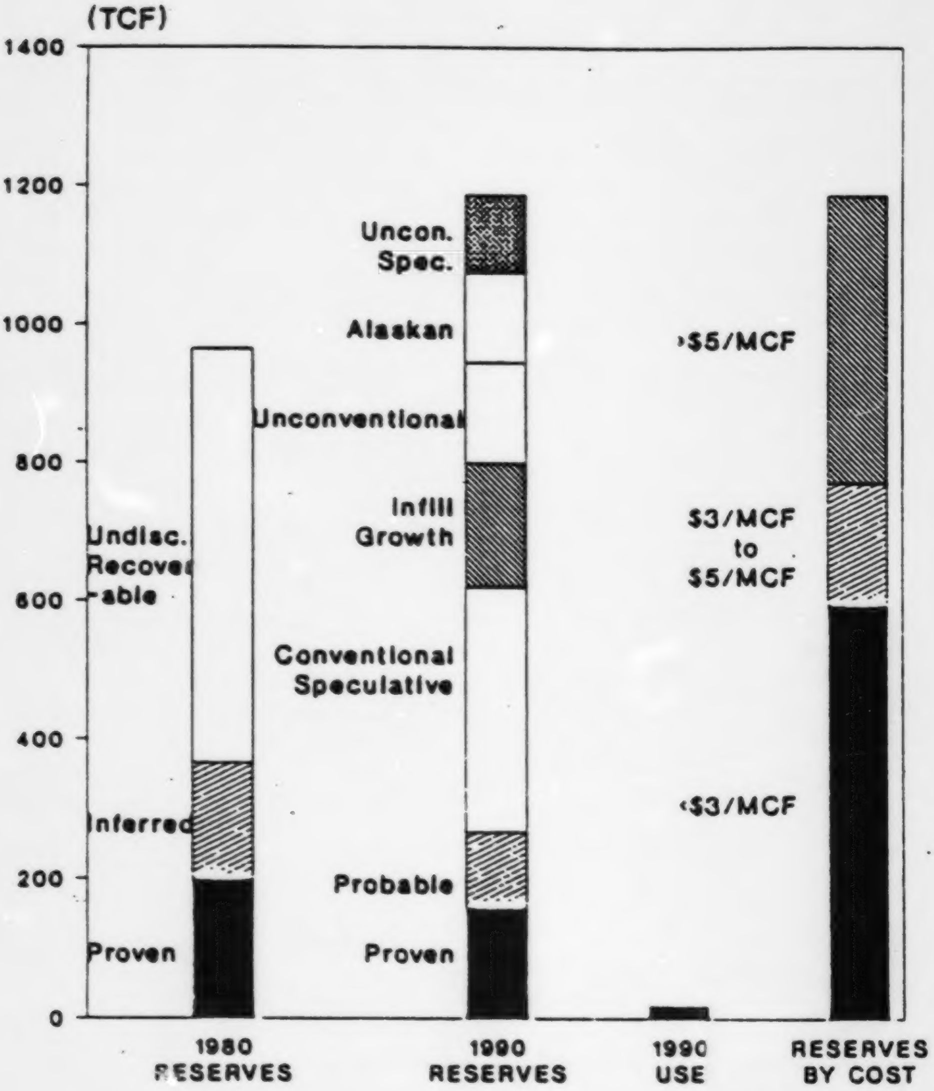

Figure 3-1 U.S. Natural Gas Resources (Mueller, 1991)

4.0 Natural Gas Processing

Natural gas delivery requires collection, processing, transmission and distribution facilities. Collection requires the installation of feeder pipelines from remote natural gas wells to central collection pipelines which terminate at the processing plant.

The natural gas processing facilities of Westcoast Energy Inc. are at Taylor (McMahon), Boundary Lake, Fort Nelson, Aitken Creek, Sikanni and Pine River. These plants, together with some producer-owned plants receive natural gas from the gathering pipelines and process the natural gas to separate the natural gas liquids (eg. propane, butane, ethane) and scrub the sulphur. These commodities are sold as by-products of natural gas operations. The cost of natural gas gathering and processing by Westcoast is approximately 44 cents/GJ (in 1990 dollars at 100% load factor)[16].

The peak day deliveries of residue natural gas (ie. natural gas after processing) from the Westcoast Energy Inc. facilities are expected to increase from 1869 MMcf/d (53 Mm^3/d) in 1992 to 2197 MMcf/d (62 Mm^3/d)in 1996[1]. The estimates include processing a small amount of Alberta natural gas (an average of about 85 MMcf/d or 2.4 Mm^3/d) over the forecast period. The reliance on unproven reserves to supply the processing facilities is forecast to increase from 2% of total deliverability in 1992 to 19% by 1996.

To meet increased demand, Westcoast is significantly expanding facilities at Taylor and modifying the Sikanni Plant. Westcoast is also planning a major plant expansion at Pine River[1].

5.0 Natural Gas Transportation

5.1 Introduction

The capacities of the natural gas pipelines are summarized in Table 5-1[7]. The demand for natural gas and hence the cost of transportation is seasonal with demand and price being lowest in the summer and highest in the winter. This variation produces differing availability of natural gas based on the demands for pipeline capacity which is explained in Section 6.0.

The installation of new pipeline facilities may require new firm natural gas contracts or revenue guarantees because of the high installation cost of new pipeline facilities, but firm contracts for utilities could limit flexibility in power plant operation.

5.2 Canadian Pipelines

After processing, the natural gas in B.C. enters the pipeline for transportation through Westcoast Energy to Alberta Natural Gas and possibly Pacific Gas Transmission to California, Pacific Northern Gas to Prince Rupert or Westcoast Energy to southern and central B.C. or through Northwest Gas for sale in the U.S. Pacific Northwest (Figure 5-1)[1]. Exports of natural gas to the Pacific Northwest enter the U.S. from Huntingdon, B.C. Natural gas transported by Alberta Gas reenters B.C. at the Crowsnest Pass, serves southeastern B.C. and enters the U.S. at Kingsgate. Natural gas from Pacific Northern Gas serves communities between Vanderhoof and Prince Rupert and Kitimat. Westcoast Transmission sells natural gas to B.C. Gas which distributes it in the B.C. Interior and the Lower Mainland. The B.C. Gas firm take at Huntingdon was 390 MMcf/d (11 Mm^3/d) for 1991[7]. Pacific Coast Energy transports and distributes natural gas to Vancouver Island. Initially supplies for the Vancouver Island natural gas pipeline will come from the Coquitlam takeoff of B.C. Gas and should not interfere with Burrard operation because of the small demand. Eventually, possibly between 1994and 1996, the natural gas pipeline supplying the Vancouver Island pipeline and the Burrard Thermal Plant will be re-enforced with a 36 inch line.

Presently there are no major bottlenecks on either the Westcoast transmission or B.C. Gas distribution systems. With sufficient lead time, increases in demand for pipeline capacity can be accommodated. Significant looping and additional compression facilites are planned by Westcoast which would increase throughput by 339 MMcf/d (9.6 Mm^3/d), but these plans will only proceed if Westcoast aquires long term firm contracts for the additional natural gas. Much of the Westcoast Energy pipeline from northeast B.C. to the Lower Mainland is looped, that is, there are 2

Table 5-1 CAPACITIES OF FACILITIES

Westcoast Energy:

		MMcfd	$10^3m^3/d$	PJ/a
Pipeline (south)		1502	42530	599
Processing Plants:				
Taylor	Raw Gas[1]	680	19255	271
	Residue Gas[2]	620	17556	247
Fort Nelson	Raw Gas	823	23291	328
	Residue Gas	760	21508	303
Pine River	Raw Gas	274	7752	109
	Residue Gas	200	5660	80
Subtotals	Raw Gas	1777	50298	708
	Residue Gas	1580	44724	630
Other Facilities (Approximate):				
	Residue Gas	>920	>26050	>367
Total	Residue Gas (Approx.)	2500	70789	997

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1. Taylor capacity includes an expansion of 90 MMcfd in 1990.

2. Residue gas is marketable sales gas.

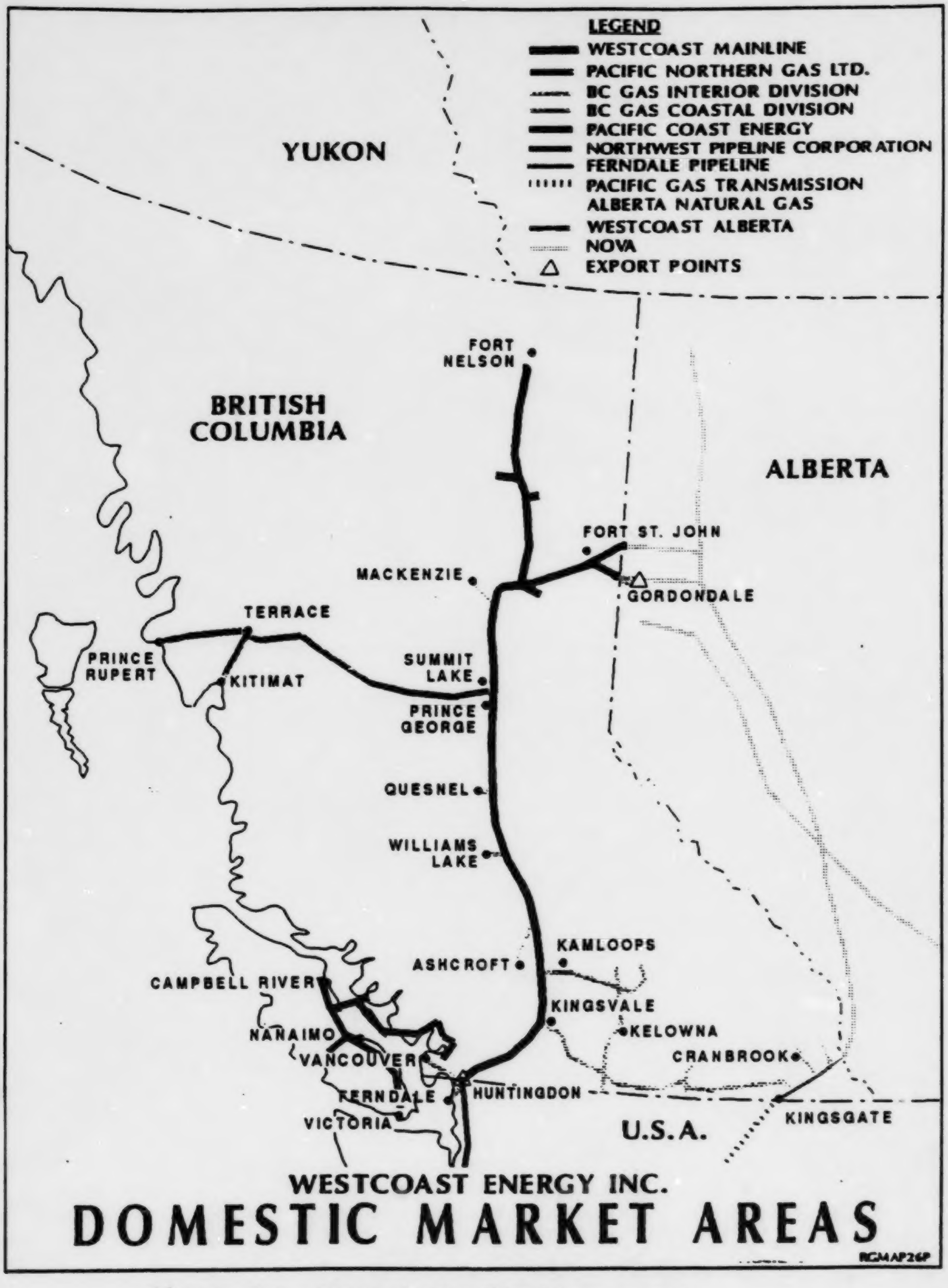
LEGEND
WESTCOAST MAINLINE
PACIFIC NORTHERN GAS LTD.
BC GAS INTERIOR DIVISION
BC GAS COASTAL DIVISION
PACIFIC COAST ENERGY
NORTHWEST PIPELINE CORPORATION
FERNDALE PIPELINE
PACIFIC GAS TRANSMISSION
ALBERTA NATURAL GAS
WESTCOAST ALBERTA
NOVA
EXPORT POINTS
YUKON
BRITISH COLUMBIA
ALBERTA
FORT NELSON
FORT ST. JOHN
MACKENZIE
GORDONDALE
TERRACE
PRINCE RUPERT
KITIMAT
SUMMIT LAKE
PRINCE GEORGE
QUESNEL
WILLIAMS LAKE
KAMLOOPS
ASHCROFT
CAMPBELL RIVER
KINGSVALE
KELOWNA
NANAIMO
VANCOUVER
CRANBROOK
FERNDALE
HUNTINGDON
VICTORIA
U.S.A.
KINGSGATE
WESTCOAST ENERGY INC.
DOMESTIC MARKET AREAS
RGMAP26P

Figure 5-1 Natural Gas Pipelines - B.C.

pipelines side-by-side. It is planned to loop the last sections of the Mainline South pipeline by 1993[1]. Therefore, the capacity of these lines could be doubled.

New firm service on the Westcoast System into the Lower Mainland normally requires a wait of approximately 2 years to provide the capacity. However, because of a considerable queue of capacity requests, the present wait may be longer. In the long term, Westcoast expects that there will be less problems in installing new capacity.

The Vancouver Island natural gas pipeline began delivering natural gas to parts of Victoria recently and new areas are being added as quickly as possible. Despite these additions, pulp mills are expected to be the biggest users as they replace their use of fuel oil for steam production. By the year 2000, it is expected that annual demand on Vancouver Island will be 22 PJ. However, the forecast may be too high. It should also be noted that there is considerable concern in B.C. Hydro System Planning over the vulnerability of the underwater electric transmission system to Vancouver Island. One alternative being considered is additional electricity generation on the Island. Unfortunately, most new generation on the Island would be dependent on natural gas and a pipeline to the Island which would be as vulnerable as the submarine electric transmission system.

5.3 U.S. Pipelines

The location of western U.S. pipelines are illustrated in Figure 5-2[24]. The combined capacity of the Northwest Pipeline and Pacific Gas Transmission pipelines after a small recently proposed expansion will be approximately 1.7 Bcf/d (48 Mm^3/d). The average excess capacity on this line in 2005 varies by month as listed in Table 5-2, assuming a medium gas-growth scenario in the non-utility sectors. The table indicates the probability that the excess pipeline capacity will exceed the value in the column. For example, there is a 50% probability that the excess pipeline capacity will exceed 1.10 Bcf/d (31 Mm^3/d) in July, 2005. Each 100 MW of capacity would require approximately 0.0165 Bcf/d (0.47 Mm^3) of fuel (assuming combined cycle plants with 50% thermal efficiency). The table indicates that there is a 50% probability that 2000 MW of new generation could not be sustained in January, February and possibly December, the months when there is the highest demand for the generation. A significant increase in export pipeline capacity or curtailment of large numbers of non-firm customers would be required to sustain such a large increase in natural gas-fired generating capacity in the Pacific Northwest of the U.S. Simple cycle combustion turbines with lower efficiency (approximately 40%) may be used to firm up secondary energy, but even this has risks because the periods of high demand for gas-

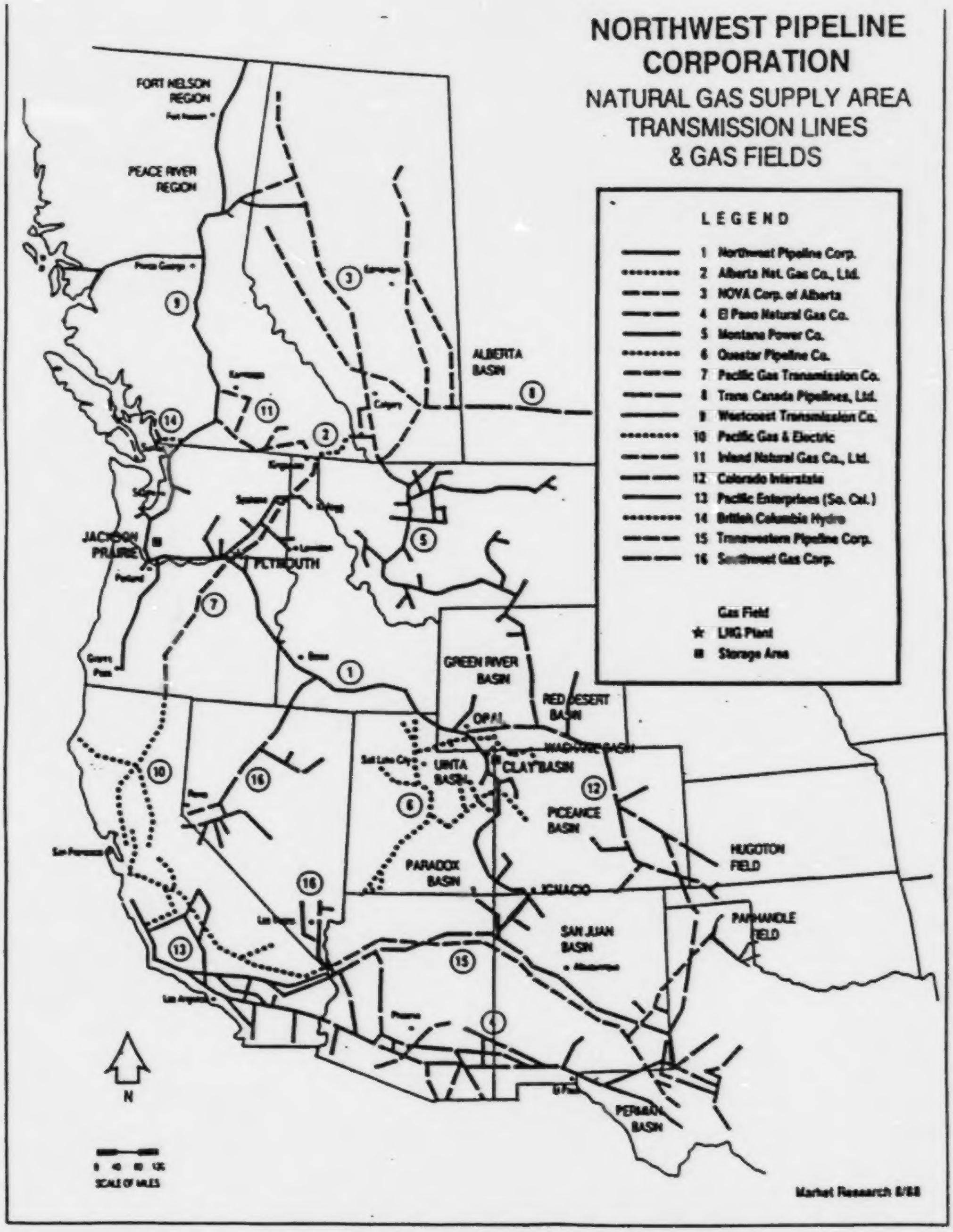
NORTHWEST PIPELINE CORPORATION
NATURAL GAS SUPPLY AREA
TRANSMISSION LINES
& GAS FIELDS
LEGEND
1 Northwest Pipeline Corp.
2 Alberta Nat. Gas Co., Ltd.
3 NOVA Corp. of Alberta
4 El Paso Natural Gas Co.
5 Montana Power Co.
6 Questar Pipeline Co.
7 Pacific Gas Transmission Co.
8 Trans Canada Pipelines, Ltd.
9 Westcoast Transmission Co.
10 Pacific Gas & Electric
11 Inland Natural Gas Co., Ltd.
12 Colorado Interstate
13 Pacific Enterprises (So. Cal.)
14 British Columbia Hydro
15 Transwestern Pipeline Corp.
16 Southwest Gas Corp.
Gas Field
★ LNG Plant
■ Storage Area
FORT NELSON REGION
PEACE RIVER REGION
ALBERTA BASIN
JACKSON PRAIRIE
PLYMOUTH
GREEN RIVER BASIN
RED DESERT BASIN
OPAL
WASHAKIE BASIN
UINTA BASIN
CLAY BASIN
Salt Lake City
PICEANCE BASIN
HUGOTON FIELD
PARADOX BASIN
IGNACIO
SAN JUAN BASIN
PANHANDLE FIELD
PERMIAN BASIN
San Francisco
Los Angeles
Las Vegas
Portland
Boise
Albuquerque
Phoenix
N
0 40 80 120
SCALE OF MILES
Market Research 8/88

Figure 5-2 Natural Gas Pipelines - Western U.S.

Table 5-2 Average Excess Capacity on the Northwest Pipeline in the Pacific Northwest in 2005

Probability of Excess Capacity for Medium Growth Scenario (1.70 Bcf/d or 48.1 Mm^3/d maximum)

Month	approx.100%	75%	50%	25%	approx.0%
January	-.11	.16	.25	.34	.61
February	.01	.19	.25	.32	.50
March	.39	.53	.58	.63	.77
April	.52	.63	.66	.70	.81
May	.63	.79	.84	.90	1.06
June	.86	.97	1.01	1.05	1.17
July	.97	1.07	1.10	1.14	1.24
August	1.00	1.10	1.13	1.16	1.26
September	.88	1.03	1.08	1.13	1.27
October	.69	.87	.93	.99	1.16
November	.46	.63	.68	.74	.91
December	.03	.26	.34	.42	.65

fired generation are likely to correspond with high demand for natural gas for heating. The reservoirs for hydroelectric generating facilities could be used to store some energy from these combustion turbine facilities, but capacity would still be a problem.

A substantial increase in sales of B.C. natural gas to western U.S. customers would require improved pipeline access. Present pipeline access into California, the largest potential natural gas market, is limited to either small interruptible sales or firm sales to Alberta and Southern (A&S) which purchases natural gas for its parent company, Pacific Gas and Electric (PG&E).

Export pipelines are near capacity at peak periods and additional natural gas will likely be exported only during the off-peak. The pipelines in the U.S. could also increase their capacity through the construction of new facilities. New facilities could enable the pipeline companies to take natural gas at the B.C. border and transport it to customers in areas not presently accessible to B.C. natural gas. The new facilities would increase demand for B.C. natural gas which could ultimately increase its price.

In order to satisfy some of the demand for additional natural gas in the U.S., the following new pipelines have been proposed[7]:

- An expansion of the Pacific Gas Transmission (PGT) pipeline to supply an additional 750 MMcf/d (21 Mm^3/d) to California and 150 MMcf/d (4 Mm^3/d)to the Pacific Northwest.
- the new Kern River pipeline with an initial capacity of 700 MMcf/d (20 Mm^3/d) from Opal Wyoming to southern California by early 1992.
- the new Altamont pipeline with a capacity of 700 MMcf/d (20 Mm^3/d)from southeast Alberta to the northern end of Kern and expansion of Kern to 1200 MMcf/d (34 Mm^3/d) with the surplus 200 MMcf/d (6 Mm^3/d) going to the midwest through existing pipelines.
- El Paso and Transwestern plan to expand their lines into California from Texas and New Mexico by 400 MMcf/d (11 Mm^3/d) and 340 MMcf/d (10 Mm^3/d) respectively.
- Northwest Pipeline plans a major pipeline looping and increased compression from Huntingdon to Wyoming which would add 534 MMcf/d (15 Mm^3/d) of capacity by 1993.

Not all of these proposals will proceed. The Kern River pipeline is the only one currently under construction. The Pacific Northwest of tne United States has been traditionally the market for B.C. natural gas. Expansion of the PGT pipeline with allowance for 150 MMcf/d (4 Mm^3/d) for the Pacific Northwest will increase competition in the area and could depress natural gas prices. A major restructuring of firm service contract arrangements for pipeline access through Alberta could permit access for B.C.

natural gas to diverse markets in eastern Canada, the U.S. midwest and U.S. northeast.

5.4 Discussion

Several potential problems must be considered in examining the impacts of new natural gas-fired generation on the natural gas transportation system. The gas pressure required for simple cycle aeroderivative combustion turbine plants is as much as 6 times the gas pressure needed for gas-fired thermal plants and this must be considered in the plant design[25]. Large combustion turbine plants are like cities to a gas pipeline in that their draw is so large; the impact is felt most strongly at start-up and shut-down.

There is an inherent problem in the increased use of natural gas by utilities which results from a lack of familiarity among natural gas suppliers, transporters and utility customers. Generally, utilities have relied on interruptible supplies of natural gas and suppliers and transporters have little experience with conditions in which utilities are relying on them for a firm supply. Utilities typically think in terms of power pools when they experience a shortage. However, in the analagous situation, gas suppliers and pipeline operators curtail delivery rather than construct surplus capacity. The current surplus capacity throughout most of the U.S. and Canada is the result of a decrease in demand for natural gas from 1972 to 1986. As the surplus is exhausted, utilities can expect to face ever-increasing curtailments.

U.S. natural gas is likely to become more competitive with Canadian natural gas in the U.S. market which is likely to reduce the rate of increase in exports. U.S. natural gas suppliers have been complaining for some time that the Canadian rate structure has provided an unfair advantage for Canadian suppliers in the U.S. market[26]. U.S. suppliers have requested punitive charges to supposedly level the playing field. However, U.S. regulators have resisted this action until now and they have proposed the "Mega-NOPR", the Federal Energy Regulatory Commission's (FERC's) NOtice Of Proposed Rule-Making. The "Mega-NOPR" will govern natural gas-fired projects, unbundle natural gas sales from transportation charges, provide equivalent access to pipeline transportation and reduce the commodity charge while increasing the fixed charge to make them more in line with Canadian charges. However, these new proposals, which are expected to take effect on 1 October, 1992, have been criticized as unfair to dispatchable IPPs because of the higher demand charge on firm natural gas.

6.0 Pipeline Transmission and Contracts

6.1 Contracts

The price of natural gas is dependent on the type of contract between the supplier/transporter and the customer. These types include firm gas and interruptible gas such as valley gas, swing gas, spot gas and seasonal gas. B.C. natural gas is sold on the North American market under 3 main categories of contracting: spot, short term firm and long term firm and these contracts are principally dependent on the reservation of pipeline capacity[7,16].

Spot gas is natural gas which results from the simultaneous availability of unused firm capacity from the point of production to the point of consumption. Spot gas sales may be curtailed by buyer or seller. However, the transporter may only curtail spot gas shipped under interruptible transportation service. The price is usually established by negotiation or bid for one month. Spot natural gas is expected to be available at high levels at Huntingdon through the mid-1990s and the commodity price is expected to increase at rates comparable to those for valley natural gas (ie. track wellhead prices - increase at 1.2 %/a for 5 years or 3.3%/a for 20 years (1990 $/GJ).

Firm gas is natural gas which the seller and transporter have committed to supply and the buyer has committed to take, each subject to force majeure. Firm gas sales may be short term or long term, but the distinction between them is somewhat arbitrary.

Long term firm natural gas sales are essentially those which continue beyond a time when the price can be fixed. Therefore, they require a redetermination process which may be renegotiation, price set by a predetermined formula or, failing that, by arbitration. Long term sales may require development expenditures to substantiate the contracted reserves. Presently the B.C. Government requires that the natural gas producer have only 50 percent of the contracted amount on signing a long term contract. The assumption is that the producer will be able to confirm additional reserves to meet the contract either through discovery or purchase.

Short term firm natural gas sales contracts are of sufficiently short duration that the price can be fixed, or rarely, based on a fixed formula. The term could be as long as 3 years for domestic contracts, but under the National Energy Board (NEB) regulations, the duration can be no longer than 2 years for export contracts.

Interruptible gas is natural gas which is discretionary for buyer, seller and transporter. The seller and transporter agree to make a minimum quantity available over the year and the buyer agrees to take that amount or let it accrue as long as the 4 year running average is equal to or more than 4 times the quantity of interruptible gas contracted for the period. Prices are determined by the price to the seller plus an agreed transportation charge.

Swing gas is natural gas which the seller has committed to purchase from third parties on a daily basis to reduce the level of curtailment to its interruptible sales customers and to provide volumes requested by the buyer. Some or all of the swing gas will be surplus to the seller's requirements on some days during the term of the agreement. On days when the seller does not require some or all of the swing gas purchased, the seller makes the surplus available to the buyer. During the peak period, buyer and seller may agree on certain take-or-pay provisions. Setting aside a specifed amount of natural gas for the buyer requires payment of a reservation charge in addition to the normal commodity charge.

Valley gas is the unused portion of firm gas service which is left when all other gas demands are satisfied. It is available in the summer months when demand for natural gas is lower because less is required for space heating. Valley gas sales enable the seller and transporter to maintain an improved cash flow during this "slack" period.

Seasonal gas is natural gas which can be purchased by the seller over and above its system requirements up to the limit nominated in its natural gas supply agreements with third parties.

6.2 Burrard Thermal Plant

The Burrard Thermal Plant purchases natural gas under several of the above contracting mechanisms. Some firm natural gas is required for Burrard during the winter (to run Burrard at a minimum for voltage support). B.C. Hydro's swing gas contract with B.C. Gas has a term of 2 years (1991/92-1992/93) with a commodity charge of $1.50/GJ and a $1.3 M reservation charge (Resource Management Monthly Report Aug./91). This is equivalent to a price of approximately $1.87/GJ for natural gas delivered to Burrard with a minimum take of 3.5 PJ. Prices are expected to escalate at or slightly less than increases in wellhead prices.

B.C. Hydro tries to make use of valley gas for Burrard Thermal Plant when scheduling and ambient air quality permit. The valley gas contract is a hybrid between a firm and spot commitment. The producer must supply the gas on request if it is available, but B.C. Hydro is not obliged to take it.

The price of valley gas (seasonal gas) is usually 35% below the normal interruptible natural gas supply (spot gas) price. The valley natural gas price for B.C. Hydro in the 1990/91 fiscal year for a take of 20 PJ/a or more was $1.30/GJ. The valley gas price is expected to increase at 2.3 %/a through 1997 for the reference case[16], remain flat for the sustainable low and increase at 8.0 %/a for the sustainable high (all in 1990 $/GJ plus GST). B.C. Hydro purchases valley gas from B.C. Gas for Burrard for an annual demand charge of $5 M, a commodity charge of $0.93/GJ and a commodity toll of $0.04/GJ. For a take above 20 PJ/a, an additional transportation and toll charge of $0.29/GJ is added[27]. B.C. Gas estimates that there will be between 30 PJ and 40 PJ available each year until 1998. It is expected that valley gas will continue to be the base source of fuel for the Burrard Thermal Plant with spot purchases making up any shortfall to meet increased levels of operation.

For the Burrard Utilization Study, valley gas prices, in the reference case, are expected to increase by 2.3%/a (real) until 1997 in the reference case. Wellhead prices are the principal uncertainty and estimates ranged from flat in real terms for the low scenario to an increase of 8%/a (real) for the high scenario. Valley gas prices are forecast to increase by 2.7%/a (real) from 1998 to 2010 in the reference scenario (Ref. B.C. Hydro Resource Management monthly report Aug./91), which is equivalent to an increase at 1.5%/a (real) from 1990 to 2010. The current interruptible gas contract for Burrard Thermal Plant specifies an annual take of 20 PJ. The seller must provide the buyer with sufficient notice to allow the buyer to curtail operations (in the case of the Burrard Thermal Plant - 6 hours).

6.3 Other Domestic Contracts

The cost to Pacific Coast Energy Corporation for transporting natural gas from Huntingdon to Coquitlam on the existing B.C.Gas pipeline is $0.18/GJ. As volumes increase the price is expected to decrease to $0.10/GJ. The Vancouver Island natural gas pipeline transports natural gas from Coquitlam to Vancouver Island via the Sunshine Coast. The Vancouver Island natural gas pipeline is a $346 M project by Pacific Coast Energy Corporation, a joint venture by Alberta Energy Limitied and Westcoast Energy Limited, which began deliveries in September, 1991[28]. For large utility customers, the demand/commodity toll ranges from $0.83/GJ for a take of 45 TJ/d to $1.24/GJ for a take of 9 TJ/d - both are based on a 67.5% load factor[29]. The tolls would decrease by $0.15-$0.20/GJ for a 90% load factor. Prices are expected to increase at 5%/a (nominal).

6.4 Exports

The charge for transportation of natural gas from Huntingdon, B.C. to Stanfield, OR (NWP) is $0.30/MMBtu (1990 U.S.$) or $0.32/GJ (Can.$) and from Stanfield, OR to Malin, CA is $0.15/MMBtu (1990

U.S.$) or $0.16/GJ (Can.$)[7]. The cost of transportation over the PG&E pipeline from Malin to San Francisco, CA is $0.25/MMBtu (1990 U.S.$) or $0.27/GJ (Can.$). These transportation charges are competitive with delivery of natural gas to the same market from Wyoming.

A small amount of B.C. natural gas is exported to the U.S. through Alberta. B.C. natural gas is competitive with Alberta natural gas in California. Although the delivery charges for spot or short term purchases of natural gas from Texas are slightly less than those for B.C. natural gas, natural gas from B.C. is still competitive in this market at the present time[7]. Delivery charges for Texas natural gas are expected to decrease significantly in the next few years as some surcharges are dropped resulting in delivered costs of $0.25 to $0.45/Mcf (1990 U.S.$) or \$10.03/10^3m^3 to \$18.06/10^3m^3 (Can.$) less than B.C. natural gas. Therefore, sales of B.C. natural gas to potential customers in southern California will be at a disadvantage. In addition, transportation companies supplying southern California from wells in Texas and New Mexico can selectively discount their published tolls at their own discretion in order to remain competetive.

The Westcoast tolls for firm gas at Huntingdon are expected to decrease in real terms (ie. increase at about 1/2 the rate of inflation) based on the Confer report[7]. For this report, it is expected that new facilities will require increased capital expenditures, but no real increase or decrease in the cost of processing and transportation.

Panelists at the EPRI Fuel Supply Seminar in Albuquerque (1991) noted that at present short term gas contracts were in the best interests of both suppliers and customers. They provide stability in terms of known supply and demand and at the same time confidence with regard to the negotiability of future natural gas prices. However, some non-utility generators require long term contracts for financing.

7.0 Natural Gas Storage

Natural gas storage may be on surface in tanks as compressed or liquefied natural gas or underground as compressed gas. Liquefied storage of natural gas requires tank farms with low storage temperatures. Surface storage of large quantities of natural gas is impractical because of the large tank volume required. For successful underground natural gas storage, the storage should have a high capacity, satisfactory deliverability for the specific use, be as close to the market as possible and in an area with large supplies of natural gas.

The implementation of underground natural gas storage requires a great deal of planning. The characteristics of the reservoir for natural gas storage differ depending on whether the storage is required for peaking or for seasonal fluctuations in natural gas demand. Compression is required for shallow storage, whereas simply pumping the natural gas into deep reservoirs is sufficient to compress it. The reservoir should be cycled regularly to maintain the quality of the reservoir and the natural gas in the reservoir. It requires 3 to 5 years to build up underground storage and, therefore, as much as 6 to 7 years of planning to meet a particularly large peak day. EPRI has a computer model to determine an adequate storage mix and optimize underground storage[30].

Three storage facilities have been identified in B.C. and the Pacific Northwest of the U.S.[7]:

1. The liquefied natural gas (LNG) facility in Delta with a capacity of approximately 0.5 PJ.
2. Underground storage at Aitken Creek in Northeast B.C. with a capacity of approximately 3.0 PJ.
3. The underground natural gas storage at Jackson Prairie in southern Washington State has capacity for approximately 0.35 PJ of B.C. natural gas.

Therefore, there is storage capability for approximately 4 PJ which is about 2.4% of Lower Mainland and Interior B.C. purchase volumes estimated for 1992. This storage is used for peaking on the processing and pipeline system. Liquefied natural gas is the source of last resort to meet natural gas demand after interruptible customers have been cut and storage at Aitken Creek and Jackson Prairie have been utilized. Development of extensive additional natural gas storage for peak (pipeline) reduction is unlikely based on the current Fraser Valley controversy concerning underground storage. This proposed storage would replace some of the existing storage as well as provide some new storage. To provide additional peak shaving capability would require exponentially increasing volumes of natural gas storage and, in general, new storage is very expensive to develop.

Line packing, increasing the pressure in the pipeline between pumping stations and upstream from a high demand customer such as a utility, is a short term method of storage (Figure 7-1)[25]. It results in a minimal increase in costs and has widespread potential for application. However, it can only store a small quantity of natural gas and could be detrimental to other customers elsewhere on the line between the two pumping stations (Figure 7-2). Line Packing is one method of reducing the impact of combustion turbines on a natural gas pipeline. Combustion turbines can cause a severe drawdown on the pipeline on startup and a severe overpressure on shutdown. This problem occurs because of the time required for the pumping stations to respond to the impacts of these large loads on the system. The time required for 500 MW units to exhaust a line pack are illustrated in Figure 7-3. These range from 4 hours for new combustion turbines with rapid start-up to over 9 hours for a steam plant and indicate the potential impact of new combustion turbines on pipeline operations.

To improve the load factor on its distribution system, B.C. Gas is seeking contracts with interruptible customers, such as cogeneration facilities, which could be interrupted for 30 days or so in the winter season. They are also actively pursuing joint ventures with such projects in B.C. and the Pacific Northwest of the U.S.

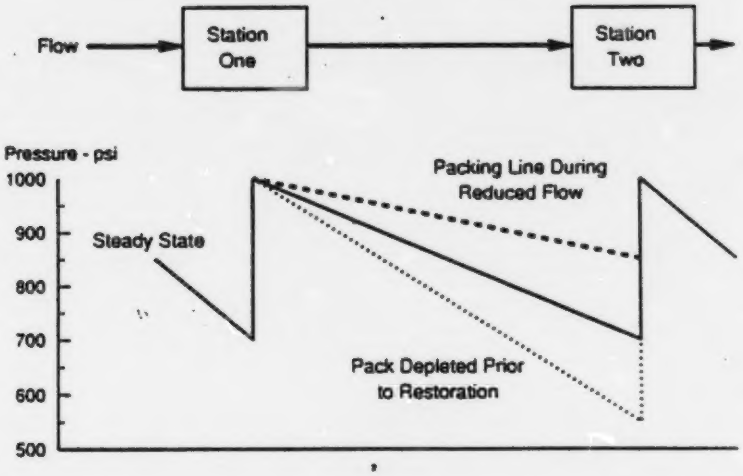

Figure 7-1 The Use of Line Pack

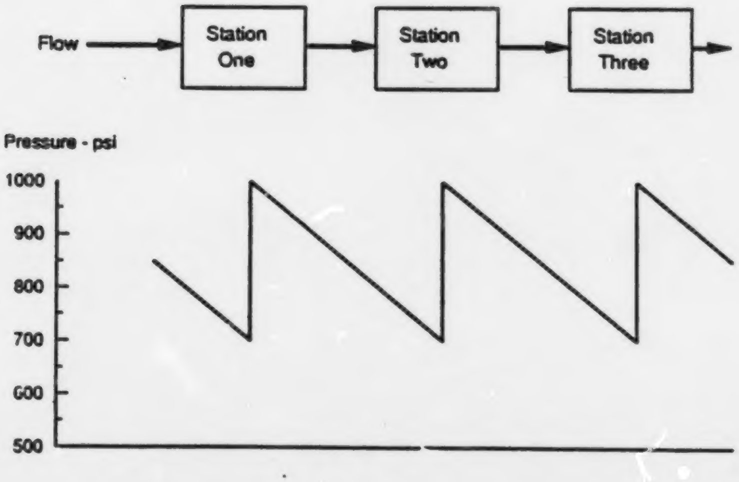

Figure 7-2 Typical Optimum Pipeline Design

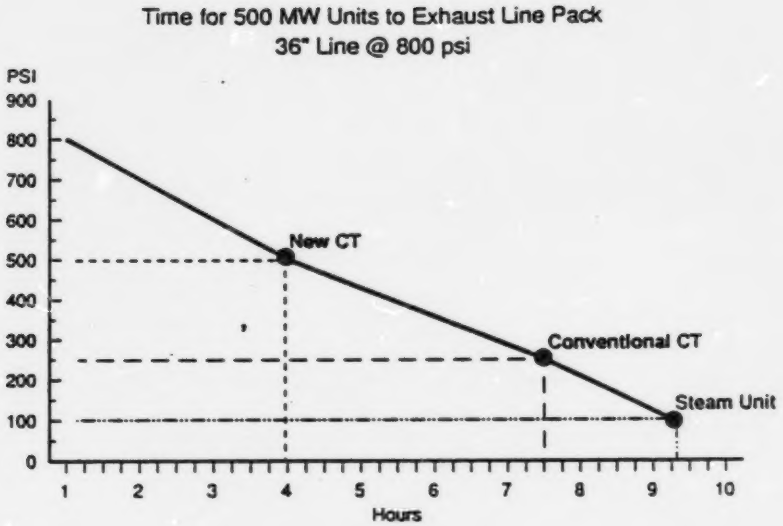

Figure 7-3 Hypothetical Line Pack Response Time

8.0 Natural Gas Markets

8.1 Characteristics of the Natural Gas Market and Utility Demand

In the 1970's demand for natural gas decreased because of its high price. Reductions in demand were accomplished in many ways, but we will list only a few of these as examples. At the commercial and residential level, insulation levels and furnace efficiencies were improved. The reduction in natural gas use was accomplished in the utility industry by fuel switching and by the dispatching of older, less efficient generating units. Efficiencies in natural gas-fired units for power generation will improve further. Many natural gas-fired units at conventional thermal plants which were designed to be base-loaded are presently being used for peaking because the high load forecasts of the late 1970s and early 1980s did not develop. The result is a surplus of generating facilities designed for base load. It is expected that all of these conventional natural gas-fired thermal plants will be retired or repowered with combustion turbines.

The type and use of natural gas-fired generating facilities affect the demand characteristics on a natural gas pipeline system. The generation can be combustion or steam turbines for utility generation, combustion turbines for environmental compliance or combustion or steam turbines for self-generation/ cogeneration. A combustion turbine may be used for peaking (usually simple cycle), cycling (simple or combined cycle) or base load (usually combined cycle). A steam turbine may be used for base load or cycling. The impact of these differing operational modes is illustrated in Figure 8-1[25]. In addition, the operating characteristics of steam versus combustion turbines are markedly different. A combustion turbine can come on and ramp up over a period of minutes and shut down as rapidly, whereas a steam turbine must ramp up or down over a period of several hours. The combustion turbine can create severe problems for a pipeline system by drawing too much natural gas from the system in a short time. They have the effect of large cities on the line, with peak loads coming on at one time (Figure 8-2a amd 8-2b). In meeting that draw, the problems for pipeline operations may differ somewhat depending on location along the pipeline. If the combustion turbine is upstream of a pumping station, there is a large pressure drop on startup. If it is downstream of the pumping station there could be a large overpressure when the combustion turbine is shut off. These characteristics make it desirable to have natural gas storage near large utility customers or possibly line-packing in which the pipeline is overpressured with natural gas during off peak hours. However, line-packing may not be an acceptable solution because it could create problems for other users on the line near the power plant.

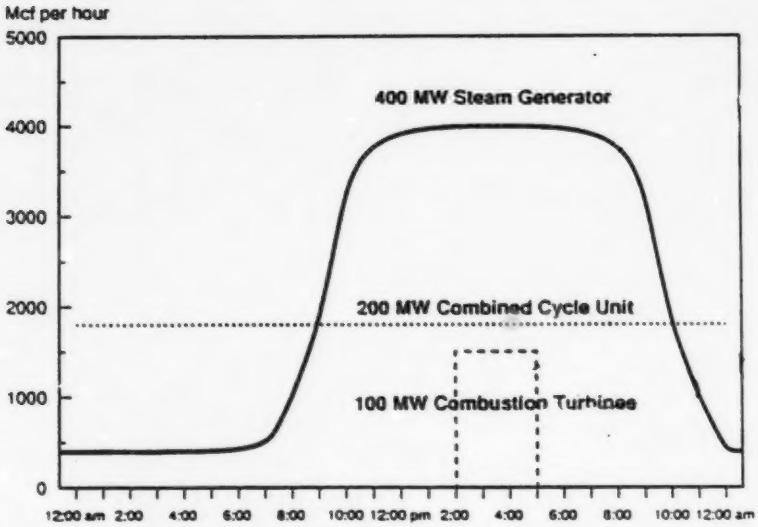

Figure 8-1 Comparison of Natural Gas Loads

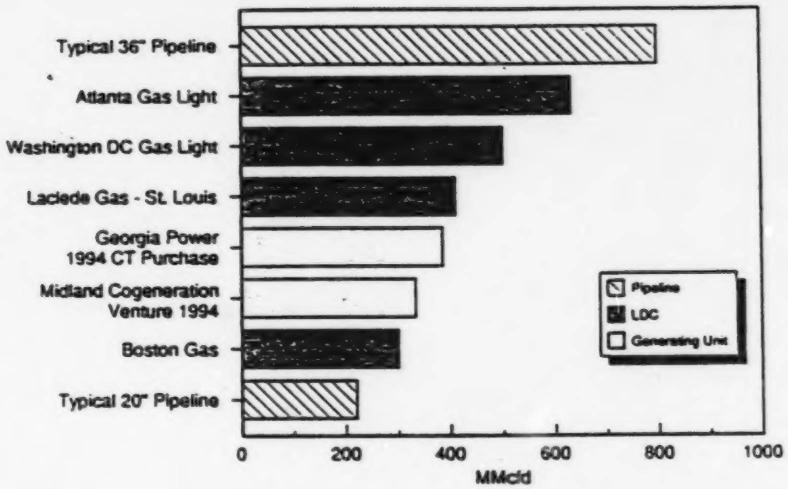

Figure 8-2a Daily Equivalent of Peak LDC & Power Plant Loads

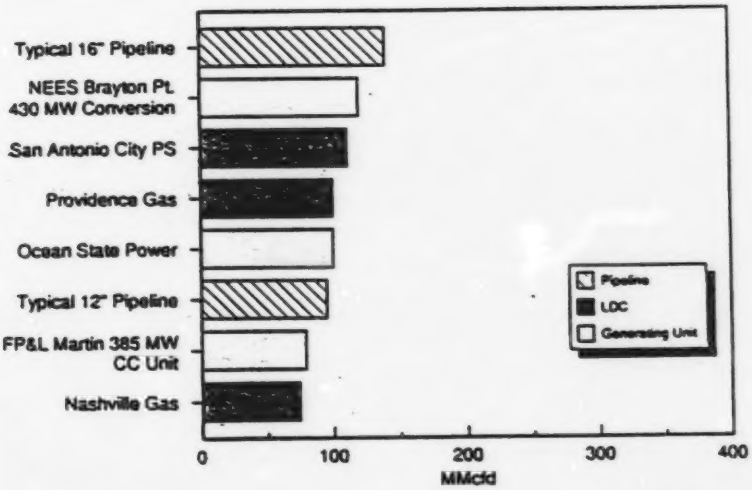

Figure 8-2b Daily Equivalent of Peak LDC & Power Plant Loads

The impetus for increased natural gas-fired generation comes not only from the increased efficiency of combustion turbines and the low price of natural gas, but also from the changes in fuel concerns over the last few years and the anticipated change in concerns over the next decade (Figure 8-3)[17]. Diversity, flexibility and especially environmental externalities are becoming more important relative to fuel security and price. The quantification of these externalities has resulted in higher unit energy costs attributable to the externalities compared with the price of the fuel itself. This new emphasis favours natural gas-firing.

8.2 Canada

During the last 10 years, domestic sales of Canadian natural gas have increased by 28%, whereas export sales have increased by 80%[8]. Despite these remarkable increases in the sales of natural gas, some wells and even some fields are shut-in and form reserves which will be developed in the future when prices and markets permit. The major new markets for natural gas in Canada over the next decade appear to be in the areas of cogeneration/self-generation/IPPs, natural gas vehicles and commercial cooling. Total natural gas demand in Canada is expected to be increased by 300 Bcf (8.5 Gm^3) by 1995[23].

Sales of B.C. natural gas are summarized in Table 8-1[7]. Natural gas sales to utilities are very small. However, domestic markets served by Westcoast Energy are expected to increase natural gas demand by 4.2% per annum through 1996 (Table 8-2)[1]. Annual deliveries are expected to increase from 214 Bcf (6.1 Gm^3) in 1990 to 276 Bcf (7.8 Gm^3) in 1996. This growth is driven by 3 factors:

1. The connection of Vancouver Island and the Sunshine Coast in 1991 and the development of markets in these areas.

2. Greater use of the Burrard Thermal Plant and the development of industrial cogeneration and IPP projects.

3. Continued strong growth in the residential and commercial sectors in the Lower Mainland.

Pacific Northern Gas, B.C. Gas Interior Division and northeast B.C. are expected to have only modest growth in natural gas demand over the next 5 years.

8.3 United States

Ms Carol Freedenthal, of Jofree Corporation, expects natural gas markets in the U.S. to increase significantly in the next 3

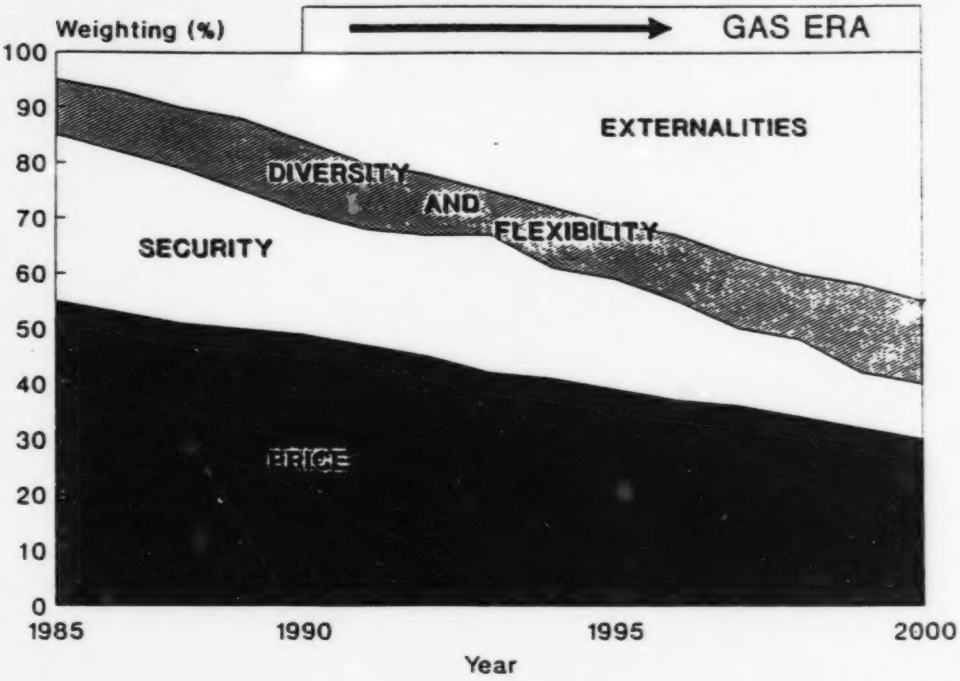

Figure 8-3 Changes in Fuel Concerns over Time

Table 8-1 Sales of B.C. Natural Gas

	MMcf/d	$10^3m^3/d$	PJ/a
Total Sales for 1990/91:			
Domestic	615	17414	245
Other Canadian	85	2407	34
Exports to U.S.	442	12515	176
Total	1141	32308	455
Domestic Sales for 1990:			
B.C. Gas Coastal Division-			
Residential	116	3285	46.2
Commercial/Industrial	110	3115	43.9
Interruptible	53	1501	21.2
Subtotal	279	7901	111.3
B.C. Gas Interior Divisions-			
Subtotal	97	2747	38.7
Other Sales-			
Pacific Northern Gas			
Transportation Only Contracts			
Burrard Thermal Plant (Valley Gas)	10	283	4
Subtotal	239	6766	95
Total Domestic Sales	615	17414	245
U.S. Sales for 1990/91:			
Pacific Northwest	371	10505	148
California	48	1359	19
Rocky Mountain and Other	23	651	9
Total U.S. Sales	442	12515	176

Table 8-2

Sales of B.C. Natural Gas Through Westcoast Energy Inc.

(Bcf/a)

	1990	1991	1996
Domestic Sales:			
Zone 3 (Northern B.C.)	13	14	19
B.C. Gas Coastal Div.	103	112	123
B.C. Gas Interior Div.	52	51	53
Pacific Northern Gas	33	33	34
Pacific Coast Energy	-	2	20
Electricity Generation	13	10	27
Subtotal	214	222	276
U.S. and Eastern Canada:			
Pacific Northwest	161	200	228
California	-	-	57
Other	12	25	43
Subtotal	173	225	328
Total	387	447	604

years[18]. She expects demand to rise by 5%/a until 1994 and prices to rise by only 6%/a (nominal) because of significant increases in reserves and imports from Canada.

A forecast prepared by EPRI indicates that the demand for natural gas in the U.S. will increase only marginally by 2.92 Tcf/a (82.7 Gm^3/a) between 1990 and 2010 and the majority of this increase (93.9%) will be for power generation[22]. A study by Enron Corporation forecasts an increase in demand for natural gas of 2.6 Tcf/a (73.6 Gm^3/a) by the year 2000[3].

The Independent Petroleum Association of America (IPAA) forecasts a natural gas demand for 1992 of 19.5 Tcf (550.3 Gm^3) an increase of 2.0 Tcf (70.8 Gm^3) from 1991[20]. They have assumed that weather patterns will return to normal from the higher than normal temperatures which we have been experiencing over the last few years, thereby accounting for part of the increase. Demand is also expected to increase because the recession will end. Total imports are expected to be 1.77 Tcf (50.1 Gm^3), up 8.1% over 1991 and almost all of these imports will be from Canada. The IPAA does not expect the amendments to the Clean Air Act to show up as increases in natural gas sales until the mid-1990s. The IPAA is also putting pressure on U.S. legislators to end what they see as unfair competition from Canadian producers in the form of low commodity charges on pipelines. The countervail duty which they are requesting would remain at least until FERC implements pipeline rate reform under the "MegaNOPR". Thusfar, U.S. legislators have not bought the IPAA's arguement. It should be noted that the Canadian pipelines have higher fixed charges to compensate for the lower commodity charges.

Almost all of the increase in demand (1.5 Tcf or 42.5 Gm^3) will be in the electric utility sector where energy demand is expected to grow by 2.2%/a to the year 2000. Approximately 28,000 MW of natural gas-fired generation are expected to enter service in the U.S. between now and the year 2000. About 1/2 of this new growth will be in the form of IPPs and projects to meet environmental compliance requirements. However, natural gas production in the U.S. could drop from 19 Tcf/a (538.1 Gm^3) to 16.4 Tcf/a (464.4 Gm^3) if prices for natural gas are 30% below the IPAA forecast price which is in the range of some forecasts (24% increase in demand and a 14% decrease in domestic supply). The decrease in price will discourage the development of new reserves. However, once the oversupply is exhausted, prices will increase in order to encourage new exploration and development, but there will be a significant time lag before these new supplies are developed. This time lag will encourage fuel price escalation.

Dual fuel power plants are a potentially large market for the increased use of natural gas. Most of the current dual fuel units in the U.S. are conventional thermal plants fired on natural gas or

No. 6 fuel oil[12]. These plants would be required to use low sulphur fuel oil (LSFO) as an alternative to natural gas if proposed legislation is adopted. LSFO (ie. fuel oil with less than 1% sulphur) will not be economically available from U.S. refiners and LSFO will be obtained from offshore sources, further increasing U.S. dependence on foreign oil. Combustion turbines use No. 2 fuel oil as an alternative to natural gas. No.2 fuel oil is also used as home heating oil and its extensive use by utilities would dry up the supply. Therefore, significant changes in refining capacity would be required to produce sufficient No. 2 fuel oil and prices would likely increase significantly. These factors affect the ability of utilities to use fuel oil, so they are being pushed toward the increased use of natural gas.

Despite these problems, many U.S. utilities are now converting their boilers from oil to dual fuel which allows them to take advantage of the benefits of natural gas while still hedging against future shortages of natural gas. In 1987, it was estimated that nominal fuel switching capability was about 4.8 Tcfe (equivalent or 136 Gm^3e) which was about 20% to 35% below prior estimates (7.2 Tcfe, 204 Gm^3e)[12]. The effective fuel switching capability is reduced by a further 0.7 Tcfe (20 Gm^3e) because of the amount of generation which is in the Southwest where natural gas is particularly cheap. Another 1.5 Tcfe (42 Gm^3e) of the nominal fuel switching capability is in areas where the alternative to natural gas is distillate which costs 20% to 40% more than fuel oil. Therefore, natural gas prices would have to go that much higher before fuel switching occurs.

As noted, utility fuel switching capability varies, not only with the location, but also with the season. In general, for the U.S. as a whole, the fuel switching capability is about 30% below the nominal average in the winter and 40% above the nominal average in the summer (Strat. DEC. Group, 1990). Total combined utility and industrial fuel switching capability ranges from 15% below in winter to 30% above in summer. The direction of the variation in capability is consistent from region to region, but the degree is different.

The eastern seaboard is forecast to have the highest growth in demand for natural gas in the U.S.[31]. To meet the increased demand, Canadian natural gas pipelines are being expanded (Table 8-3). However, California is the principal large market proposed for export of B.C. natural gas. In the near term, natural gas will be used in place of residual oil for raising steam for enhanced oil recovery, to replace oil in existing dual fuel power plants and to add new gas turbine power plants which are proposed to serve new load.

The North American Electric Reliability Council (NERC) has estimated that gas-fired, gas turbine installations will comprise

Table 8-3

Canadian Natural Gas Pipeline Expansion Projects for Export

Region Served	Bcf/a	PJ/a
Northeast	556	657
Midwest	307	363
Northwest and California		
Pacific Gas Transmission	329	389
Altamont	262	310
Total	1454	1719

These expansion projects have in-service dates ranging from 1992 to 1995 and would export principally natural gas from Alberta.

44% of new capacity additions in the U.S. between 1991 and 2000[22]. The total capacity additions will be 39,108 MW of which 27,600 MW will be combined cycle plants which are likely to be base-loaded. This estimate is considerably higher than the IPAA estimate for new natural gas-fired generation[20]. In 1990, approximately 10,000 MW was installed and most was simple cycle. The largest growth areas will be the west, southwest and midwest. Only modest growth is expected from the Pacific Northwest.

NERC's forecast of natural gas use by utilities is lower than most other estimates[12]. There are 4 reasons why the future demand for natural gas may be higher than the estimates of the electric utility industry in the U.S.:

1. Recent demand forecasts have tended to be conservative, underestimating demand and this appears likely to continue and even accelerate. Therefore, the demand for short lead-time, peaking capacity is expected to increase, thus favoring natural gas-fired combustion turbines.

2. Increasing environmental pressures such as the Clean Air Act make it increasingly difficult to use oil. These pressures may cause a loss of oil as an alternate fuel.

3. Non-Utility Generation (NUG) is growing as a percentage of future planned generation and NUGs prefer natural gas. If some of these NUGs cannot meet their contractual obligatiions, utilities would be forced to resort to short lead-time alternatives which also favor natural gas-fired combustion turbines.

4. Many utility units are reaching retirement age and the option of repowering is becoming important. With new plant sites being difficult to licence, the option of repowering is made more attractive and natural gas-fired combustion turbines are a favored choice.

As noted above, base case scenarios tend to favor the existence of adequate natural gas supplies and modest increases in electricity demand. Changes on the demand or supply side are likely to produce an increase in natural gas prices.

There has been an 80% increase in Canadian natural gas exports to the U.S. since 1986. However, almost all of this increase has been in the export of Alberta natural gas into the midwestern U.S.[8]. Based on CERI forecasts, Canadian exports of natural gas to the U.S. are expected to increase from 1.4 Tcf/a (40 Gm^3/a) in 1990 to 2.8 Tcf/a (79 Gm^3/a) in 2000 and 4.0 Tcf (113 Gm^3/a) in 2010[2].

The Gas Research Institute forecasts that exports of Canadian natural gas to the United States will be 2 Tcf/a (56.6 Gm^3) by the year 2000 and exports of LNG will be 800 bcf/a (22.7 Mm^3)[28].

In southern California, electricity demand is forecast to increase by 2%/a after allowance for conservation programs and almost all of this is expected to be met by natural gas-fired generation. Therefore, natural gas use, mostly for new electricity generation, is expected to increase from 3002 MMcf/d to 3418 MMcf/d (85 Mm^3/d to 97 Mm^3/d), an average growth rate of 0.66%/a[32]. These estimates do not include an allowance for natural gas vehicles.

The increased use of natural gas for vehicular fleet use to reduce emissions is expected to result in a significant increase in natural gas use in the United States. In most estimates, there appears to be no allowance for this potential increase in natural gas use. In B.C., most fleets have been converted to natural gas or propane where it was economical to do so.

By the year 2000, Enron Corporation forecasts that compressed natural gas will be used by 2.5 million vehicles in the U.S. (15% of commercial fleets)[3]. This translates into an estimated consumption of 500 Bcf (14.2 Gm^3) of compressed natural gas (CNG) per annum. By 2010, it is forecast that 1 TCF/a (28.3 Gm^3) will be required for 4 million vehicles[9].

Another 500 Bcf (14.2 Gm^3) increase in demand is expected from the remainder of the commercial market[3]. Residential use is forecast to grow by only 100 Bcf (3.5 Gm^3); the increase in customers is partly offset by increased energy efficiency. Industrial natural gas use is expected to increase by only 355 Bcf (10.1 Gm^3). These forecasts assume a constant crude oil price of $20.50/bbl (1990 U.S.$).

Natural gas exports to the U.S. from B.C. have grown considerably over the last few years because of colder spring and winter weather, the growth of natural gas use for heating and industrial processes and the overall competitiveness of B.C. natural gas in U.S. markets. Exports of B.C. natural gas to the U.S. are forecast to increase by about 52 Bcf (1.5 Gm^3) from 173 Bcf (6.4 Gm^3) in 1990/91 to 225 Bcf (7.9 Gm^3) in 1991/92 and to 328 Bcf (9.3 Gm^3) by 1996 (Table 8-2)[1]. At present, utilities in B.C. and the Pacific Northwest of the U.S. do not use significant natural gas for electricity generation. Electricity generation in the Pacific Northwest and California markets are the two regions where demand for B.C. natural gas is expected to increase the most. In Westcoast Energy's forecast, electricity generation is expected to have among the highest rate of growth with demand increasing from 10 Bcf (283 Mm^3) in 1991 to 27 Bcf (765 Mm^3) in 1996.

The present capacities of pipelines serving the export market from B.C. are listed in Table 8-4[7]. The average capacity utilization at Huntingdon is only 45% which leaves considerable room for additional firm capacity. These additions will be at the expense of interruptible loads during the winter months, some of which will probably be compelled to sign firm contracts as pipeline access becomes more restricted. As noted in Table 1 (Summary) and Section 5.3, there are plans for considerable expansion of existing pipeline capacities in B.C. and adjacent parts of the U.S. These expansions will permit a significant increase in natural gas exports.

Ripple et al prepared a long term forecast of natural gas demand in the Pacific Northwest of the U.S. Growth in natural gas consumption is expected to be 2%/a over 23 years, increasing the demand for natural gas from 244.7 Bcf/a (6.9 Gm^3/a) in 1987 to 385.8 Bcf/a (10.9 Gm^3/a) by 2010[24]. Most of this new natural gas demand will be from natural gas-fired combustion turbines. The demand for natural gas in the northwestern U.S. by sector and state is illustrated in Table 8-5. This information indicates that utility natural gas demand is insignificant at present, so these forecasts for rapidly increasing demand for natural gas for electricity generation are a marked depature from past experience.

An alternative forecast for increased exports of Canadian natural gas is provided by the Gas Research Institute (GRI). Power generation is the largest growth market for natural gas with 60% of the increased use of natural gas[33]. The GRI forecasts an increase in imports to the U.S. from Canada starting at 1.4 Tcf (39.6 Gm^3) in 1990, increasing to 2.0 Tcf (70.8 Gm^3) by the year 2000 and remaining essentially at that level until 2010[3]. If the Canadian government adopts an aggressive export policy, exports could increase by an additional 400-600 bcf/a (11.3-17.0 Gm^3).

Even without an allowance for increased use of additional B.C. natural gas for transportation, the annual increase in demand (domestic and export) is forecast to be 7.7%/a over the next 5 years[1]. The demand for B.C. natural gas in the U.S. is expected to increase at a faster rate than in B.C. itself. From this year onward, it is estimated that exports to the U.S. will be higher than domestic consumption.

The Pacific Northwest of the United States is B.C.'s traditional market for natural gas with exports crossing the border at Huntingdon. Gas supply from sources in other parts of the United States is limited by pipeline capacity. There is no indication of expanded pipeline capacity into the Pacific Northwest from other parts of the United States. Therefore, B.C. is likely to retain this market.

Table 8-4 EXPORT CAPACITY

	MMcfd	$10^3m^3/d$	PJ/a
Westcoast Export Capacity at Huntingdon, B.C.	809	22907	322
Northwest Pipeline Capacity at Sumas, WA.[1]	809	22907	322
PGT Pipeline Capacity at Kingsgate, B.C.[2,3]	1575	44597	628
Firm Gas Take at Huntingdon, B.C. (1991)	390	11043	155

	Huntingdon	Kingsgate
Annual Average Capacity Utilization (%)[4]	45	88
Capacity Utilization, December, 1989 (%)[4]	69	100

1. Experiences a null point on its system between Kern and PGT because gas flowing north from Wyoming and other U.S. suppliers meets gas flowing south from B.C. and Alberta.

2. The Foothills pipeline transports natural gas to the border. Most of the natural gas is from Alberta and destined for the California market. However, a small amount of this capacity is available for transporting B.C. natural gas.

3. Includes 1100 MMcfd for PG&E which is equivalent to 1020 MMcfd at the Oregon/California border, 150 MMcfd for the Pacific Northwest and 240 MMcfd for southern California markets.

4. From Anderson and Cambridge, 1991, Natural Gas Trends.

Table 8-5 Regional Consumption of Natural Gas in the Northwestern U.S. (1988)

(in MMcf/a)

State	Residential	Commercial	Industrial	Utility	Total
Washington	34,830	37,269	66,683	1,753	140,537
Oregon	21,095	18,401	39,798	0	79,295
Idaho	7,789	9,362	26,811	0	43,964
Montana	16,853	12,000	8,376	287	37,512
Total (MMcf/a)	80,567	77,032	141,668	2,040	301,308
Total (PJ/a)	95	91	167	2	356

The northern California market is very competetive with natural gas coming from Alberta, Wyoming, other parts of the United States and a small amount from northeastern B.C., the latter via pipelines through Alberta, but crossing into the United States at Kingsgate. The southern California market is served mainly with natural gas from Texas and coal bed methane from New Mexico; these sources are very competetive and provide little opportunity for increased markets for B.C. natural gas at the present time.

8.4 Discussion

The above review is based on conditions in the U.S., but these conditions and assumptions apply equally well in B.C. because the market for natural gas is a North American one dominated by the U.S. Therefore, it is prudent that B.C. Hydro examine options, so that it can have a contingency plan in place in case demands for natural gas or electricity are other than planned. The installation and operation of new natural gas-fired generation may be governed by factors other than electricity demand and unit energy cost.

The Strategic Decisions Group under contract to EPRI estimates that 33% of the energy from new generation in the U.S. by the year 2000 will be derived from natural gas-fired units[12]. This estimate compares favourably with NERC's estimate of 44% of new capacity from natural gas-fired units of which many will be peaking units. The use of natural gas units is forecast to rise slowly until 1994, then rise much more quickly as a result of new units, now in the planning stages, starting to come on line as the demand for new generation increases.

Natural gas-fired combustion turbine units could operate more frequently than economics, energy or power demand would dictate. Some of these units may be operated to meet environmental compliance requirements in which case they would probably be operated more frequently when ambient air quality is below imposed standards[25]. For self-generation/cogeneration, the use of the unit is likely to be governed by the process steam demand, unless some condensing capacity is also installed because it is often uneconomic to vent treated water.

The demand for natural gas could also be affected by least cost planning (LCP) measures which are being imposed on the natural gas utilities in the U.S. by the state public utility commissions (PUCs)[34]. However, there is no experience among regulators with LCP in the natural gas industry and they must borrow concepts from the electric utility industry where operating conditions are much different. Although, no states in the U.S. are practicing LCP in the natural gas industry at this time, 5 states are in the process of implementing it, 8 have LCP under development and 6 others have it under consideration. Those states implementing LCP include California and Nevada, those with LCP under development include Oregon and Washington and those considering it include Alaska and Colorado. Traditionally, resource planning at natural gas utilities has consisted of purchasing the lowest cost and most reliable supplies and storing these supplies where necessary. This is done by determining the expected daily demand, the provisions for natural gas supply contracts and the storage options. The focus of natural gas utilities has been on increasing sales. LCP, in the natural gas industry, includes fuel substituion, brokered natural gas sales, conservation incentives for utilities, high efficiency equipment for industry and competitive fuel promotion practices. Therefore, with an LCP approach, demand side management (DSM) or conservation becomes an equally important option. Developing programs is made difficult by the inability to forecast future natural gas prices in the way that the utility industry is able to forecast future electricity prices by looking at their avoided cost.

Another factor affecting the natural gas industry's ability to adopt an LCP approach is the structure of the industry itself. Electric utilities are vertically integated in that they control costs from generation to delivery to the consumer; natural gas utilities are not vertically integrated. Natural gas prices are governed partly by the cost of alternatives such as oil and oil prices are set by a world market not a local market. In addition, there is no base data on end-use consumption and this baseline information is required in order to initiate effective conservation programs.

Proposed increases in B.C. natural gas use for electricity generation are summarized in Table 8-6. All values are weighted to reflect the probability of project completion. It is estimated that at least 1446 MW of new natural gas-fired generating capacity (all in the form of simple cycle and combined cycle combustion turbines) will be installed in B.C. and the Pacific Northwest of the U.S. by the year 2000. In addition, several hog fuel-fired thermal and cogeneration facilities will be installed or converted from supplementary firing with oil to supplementary firing with natural gas. As a result, B.C. natural gas use for power generation will increase by 84.2 PJ/a of which 70.2 PJ/a will be consumed in southwestern B.C. and northwest Washington. With the proposed increases in demand for natural gas, the firm natural gas take at Huntingdon would increase from 155 PJ/a (Table 8-4) to approximately 200 PJ/a.

Table 8-6 Proposed Increases in Natural Gas Utilization[1]

Location	Capacity (MW)	Energy (GW.h/a)	Natural Gas Use ($10^6 m^3$/a)	Natural Gas Use (PJ/a)
Lower Mainland	203[2]	1588[2]	434[3]	16.3[3]
Vancouver Island	79[4]	631[4]	217[5]	8.1[5]
Interior B.C.	352[6]	2680[7]	374[8]	14.0[8]
N.W. Washington	812	5807	1323	45.8
Subtotal S.W. B.C./N.W. Wash.			1974	70.2
Total			2348	84.2

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[1] Natural gas use has been weighted to reflect the probability of plant operation.

[2] These estimates include only new or additions to generating facilities. Approximately 37% of these facilites are proposed for export.

[3] Natural gas use includes natural gas required in converting hog fuel-fired plants from supplementary oil to supplementary natural gas as well as for the addition of new natural gas-fired plants.

[4] No projects are for export. Only new projects are included.

[5] None of the projects are for export. Natural gas use includes includes conversion of supplementary oil firing to supplementary natural gas firing and the addition of new generating facilities.

[6] Includes new facilities only. Approximately 44% of the proposed capacity is for export.

[7] Energy is generated from new projects only. It is estimated that 45% of the energy from these projects would be exported.

[8] All of the gas use would be in new plants. It is estimated that 46% of the generation from these plants would be exported.

9.0 Generation Technology

Combustion turbines are the favored technology for new power generation for the following reasons:

1. There is considerable uncertainty with load growth forecasts. Utilities were left with considerable excess capacity in the early 1980s and they do not want to repeat that mistake. Therefore, they are looking to projects such as combustion turbines which have short lead times.
2. The capital cost of combustion turbines is low and the utilities are relying increasingly on IPPs and self-generators who do not want to expose themselves to high financial risk.
3. New combustion turbine technology is very efficient with fuel efficiencies as high as 42% for simple cycle and 52% for combined cycle and the potential to increase the efficiency to 85% with cogeneration.
4. Combustion turbines are reliable, so that lifetime capacity factors of 80% are possible, with annual capacities which are much higher in the near term.
5. Combustion turbines are capable of rapid start-up and they are suitable for peaking or emergency power.

Computer dispatch is becoming important in the utility industry and it favors units which can be brought on and off-line quickly. Computer dispatch is used by utilities such as Houston Lighting and Power to dispatch various sources of generation[35]. The computer dispatch program checks the demand/load balance every 2 seconds and does a complete recalculation of this demand/load balance every 2 minutes. The least economical unit is dispatched where it is practical to do so. The dispatch program examines all of the operating costs, including the fuel cost. Therefore, close coordination is required between the buyer, seller, gas dispatcher and electricity dispatcher.

Fuel cells are expected to be commercially available before the year 2000. Fuel cells usually use hydrogen, which is derived from natural gas, as a source of fuel for electricity generation. This technology offers potentially high efficiency conversion of fuel to electricity, potentially as high as 60 percent. The units are modular and small. In addition, emissions are low, making siting of fuel cell power plants easier than with conventional units. However, costs are high, but they are expected to decrease rapidly as the technology develops.

10.0 Alternate Fuels

PG&E have recently estimated the cost of other fuels as alternatives to natural gas if natural gas is unavailable (Figure 10-1)[36]. All fuels are expected to cost more than natural gas, but the costs of distillate, low sulphur fuel oil, liquid natural gas, liquid petroleum gas and crude oil would be only marginally more. These cost estimates assume level 1 emission controls in the U.S., but they do not include consideration of environmental externalities which would tend to further favour natural gas.

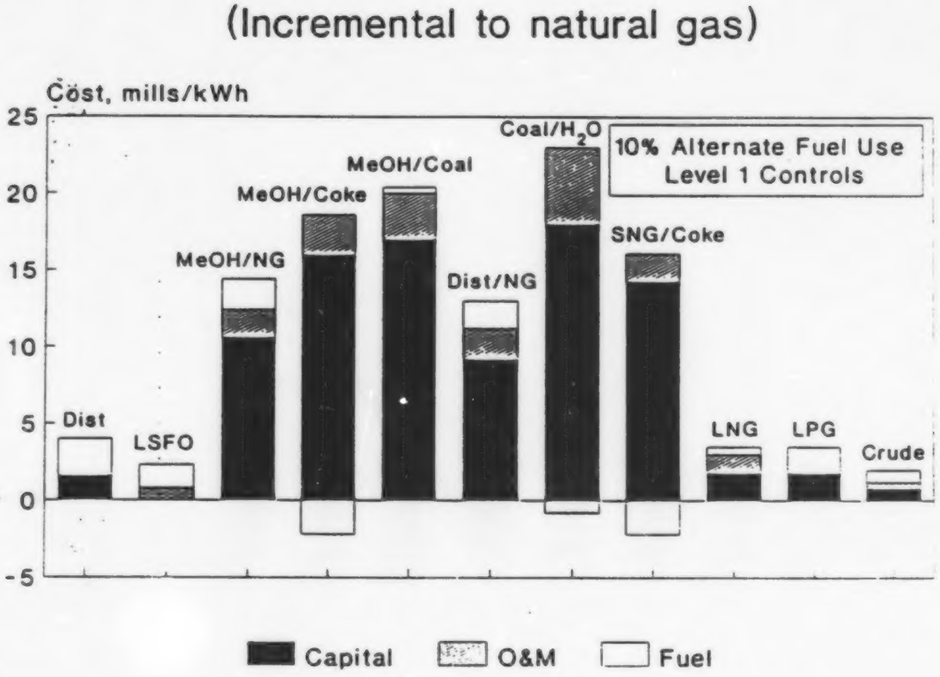

Figure 10-1 Alternate Fuel Cost Breakdown

11.0 World Oil Markets

Many of the thermal generating facilities in the U.S. are dual fuel facilities which can use oil or natural gas, so it is useful to examine briefly world oil markets and the availability of fuel oil. World oil supply and demand are summarized in Table 11-1. There is expected to be a surplus of crude oil until after the year 2000, but there may be shortages of specific fuels derived from the crude oil because of shortages of some types of refining capacity. Residual oil can be substituted for natural gas in dual fuel boilers and number 2 fuel oil can be substituted for natural gas in combustion turbines when natural gas prices are too high as occurred in 1975. However, natural gas will be the fuel of choice in the U.S. to help in complying with the Clean Air Act and possibly because of actions required to solve the greenhouse problem.

In addition to residual oil having the potential to substitute for natural gas in dual fuel boilers for thermal power generation, more residual oil boilers can be converted to dual fuel status for improved flexibility and to meet environmental regulations. In the short term, utilities can reduce their take of residual oil by as much as 45 million B/d[*1] by switching dual fuel units to natural gas. In the longer term, 3 to 5 years, about 184 million B/d or 29% of utility residual oil consumption can be reduced by converting to dual fuel and removing some constraints on the natural gas supply[37]. The use of natural gas for compliance in dual fuel boilers is described in the section on environmental factors. The constraints on natural gas supply which could limit fuel switching include pipelines which are near capacity, upgrades required on small lines, locations in urban areas where it is difficult to lay new pipelines, locations at the end of distribution pipelines and present distances from pipelines to power plants. In addition, some units must be derated when using natural gas and some of these units are too old to justify conversion, particularly if the units are used only for peaking.

In recent years world oil prices have been controlled, often ineffectively, by OPEC. Saudi Arabia and the United States have formed an unofficial coalition (USSA) which has effectively replaced OPEC in controlling world oil prices. Saudi Arabia has the oil reserves to stabilize prices using a low price-high volume strategy. The United States has the military muscle to ensure no one, internal or external, interferes with these Saudi policies which are advantageous to the U.S. economy, an economy increasingly dependent on foreign oil[38]. From the U.S. perspective, the Gulf War provided proof of the benefits of this policy in that the oil crisis generated by events leading to the War produced a significant, but only brief rise in oil prices. Increases in production from Saudi Arabia and others, the threat of the release

Table 11-1 World Petroleum Outlook

	1990	1995	2000
World Oil Supply (MMB/D)	66.11	69.36	71.34
World Oil Demand (MMB/D)	63.74	66.05	67.80
Crude Oil Prices (WTI-$/B, 1990 U.S.$)	24.45[1]	21.86	21.89

1. Higher average price due to brief price escalation resulting from the Persian Gulf Crisis.

of significant strategic reserves and the oil futures market buffered a sustained increase in prices.

The projected world price for crude oil is expected to be $24/bbl in the year 2000, rising to $37/bbl by 2010 (1991 U.S.$)[33]. The incremental production cost of providing an additional 400 thousand or more barrels/day of low sulphur fuel oil (LSFO) from U.S. refineries is estimated to be about $2.10/bbl (1989 U.S.$). The incremental cost of providing an equivalent 400 thousand barrels/day of No. 2 fuel oil is about $0.50/bbl (1989 U.S.$). Above about 780 thousand barrels/day the incremental cost No.2 fuel oil is less than the incremental cost of LSFO. However, the demand for transportation grade diesel fuel and heating oil affects both the availablity and quality of No. 2 fuel oil for utilities. It is expected that there will also be a requirement to reduce sulphur-related emissions from transportation fuels and refiners will try to unload more high sulphur fuels on stationary installations such as utility boilers. This could reduce the price of fuel oil and make it more competitive with natural gas, but require the installation of sulphur scrubbing equipment. With the present distillate tankage and pipeline capacity, the U.S. system could handle an additional demand for distillate (No. 2 fuel oil) of 1 million barrels/day, although there would be local shortages.

*1 (approx. 490,000 barrels of No.2 distillate or 450,000 barrels of LSFO is equivalent to 1 TCF of natural gas)

12.0 Environmental Factors

One of the principal factors promoting the use of natural gas as the fuel of choice for power generation is the importance of environmental issues. Air emissions are the principal concern of all types of thermal plants for power generation. Natural gas has a number of benefits over other fossil fuels used in thermal plants, including low SOX, low particulates and, with controls (low NOX burners, SCR, steam or water injection), low NOX emissions. In addition, natural gas has the lowest carbon content of any fossil fuel. Therefore, natural gas produces less carbon dioxide per unit of energy than other fossil fuels. Carbon dioxide is regarded as the major contributor to global warming, a concern which has become prominent recently. However, in some juristrictions, where new pipeline corridors are required, environmental permitting for the natural gas pipeline may be as difficult or even more difficult than permitting for the generating facilities.

Environmental legislation, restricting the use of oil by U.S. utilities, could eliminate as much as 70% to 85% of the fuel switching capability from utilities[12]. This legislation could destroy the natural gas price buffer by decoupling the price of oil and natural gas. Under several proposals, most existing dual fuel boilers with no emissions allocations will be forced to burn natural gas, but they will receive no incremental emission reduction credit. These boilers are 70% to 80% of existing dual fuel capacity or 1.7 to 1.9 Tcfe (48.1 to 53.8 Gm^3) of natural gas usage. At high natural gas prices these plants would likely switch to low sulphur residual fuel oil if environmental legislation permits.

Utlities are trying to move away from quantifying environmental impacts of emissions by estimating the costs associated with the control technology. Instead, they are are trying to move toward an assessment of all of the externalities associated with the emissions. These externalities are measured in $/tonne of emissions for each component (SOX, NOX, etc.). Producing credible estimates of environmental impacts in this way may be an impossible task. The externalities could include such diverse impacts as the cost of increased incidence of asthma and other chronic medical problems, decreased crop yields and decreased tourism. In this way, the estimates for the same emission level would vary from one part of the country to the other depending on local conditions. If externalities are considered, the need for new projects could be advanced considerably because the new projects tend to be cleaner than the existing technologies which are being used for power generation. These new projects tend to use natural gas-fired combustion turbines.

It is estimated that about 1015 MW of new natural gas-fired generation will be installed in the Greater Vancouver airshed between the North Shore Mountains and Seattle over the next decade. Of this total, about 812 MW will be installed in northwest Washington. Emissions from these plants will affect air quality in Greater Vancouver and an integrated approach will be necessary to minimize environmental impacts.

13.0 Strategies for Securing a Fuel Supply for Burrard Thermal Plant

There are a number of potential strategies which B.C. Hydro could adopt in securing a fuel supply for Burrard should load growth and the subsequent resource plan identify the Burrard Thermal Plant as a significant resource to serve future demand. These strategies can be divided into 3 principal categories:

1. Bring in a partner with natural gas reserves.
2. Purchase an independent natural gas company with large shut-in reserves.
3. Obtain a long term contract for natural gas (try to minimize the fuel price reopener clauses or stay with a formula for fuel price increases which shares the risk).

By bringing in a partner with natural gas reserves, B.C. Hydro would have direct access to natural gas reserves and a hedge against future price increases. However, bringing in a partner with natural gas reserves would limit the flexibility in operating Burrard because the partner would be interested in recovering his investment through the sale of electricity and natural gas. The question is, what would B.C. Hydro bring to the table in the partnership? Some potential options are - money, a power plant or natural gas purchase contracts.

Purchasing an independent natural gas company would permit B.C. Hydro to have flexibility in the use of Burrard and in the extraction of natural gas reserves. Purchasing shut-in reserves of natural gas would provide a hedge against future shortages and higher prices for natural gas. B.C. Hydro could make a profit from the sale of both natural gas and electricity. Now is certainly the time to explore this possibility because there is still excess natural gas on the market, there are many shut-in wells and numerous natural gas exploration companies are in financial difficulty. However, having available reserves will not guarantee access to pipeline capacity and it is delivery which could pose the greatest challenge as the number of days when natural gas must be drawn from liquid storage at Tilbury Island increase beyond the capacity of the liquefaction plant to replenish its reserves. Additional storage or pipeline capacity is required soon. Another problem in purchasing shut-in wells is that they tend to deteriorate if not developed, so B.C. Hydro would be compelled to develop the reserves even if they were not required for generation. B.C. Hydro has no experience in natural gas development; therefore this expertise for development and operation of natural gas reserves would have to be purchased from a consultant or aquired through new hiring. Still another problem is that considerable capital would be committed for a long time in order to aquire and operate a natural gas producing company.

A long term natural gas purchase contract with a minimum of fuel price reopener clauses or a satisfactory formula for fuel price escalation which shares the up-side and down-side risk is another option. This requires no up-front capital expenditures and shares future price risk, but tends to lock B.C. Hydro into a contract for natural gas at prices which are considerably higher than current valley gas prices.

The costs of coal bed methane or coal gasification provide upper limits on the price of natural gas. B.C. Hydro could examine the potential for coal bed methane either at Hat Creek, where it has substantial coal reserves, or on Vancouver Island. There is considerable potential for coal bed methane on Vancouver Island, but only an outside chance of significant coal bed methane at Hat Creek because of the low rank of the coal. The addition of gas reserves on Vancouver Island would reduce the dependency on the pipeline from northeast B.C. and provide a hedge against future natural gas price increases. However, coal bed methane is usually more expensive to develop than conventional natural gas and receives a large subsidy in the U.S. as described in Section 3.2.

Coal gasification was not considered as an option because it would have to be used by a thermal or combustion turbine power plant either mine mouth or with a dedicated pipeline. A dedicated pipeline is required because the products of coal gasification are very different from conventional natural gas.

The prices for coal bed methane or products from coal gasification provide an upper limit on the price for natural gas. The prices for these commodities are variable because of wide variations in the cost of production. However, the cost of producing coal bed methane in some parts of the U.S. are as low as $0.38/GJ (1991 Can.$), but the producers received about $2.34/GJ (1991 Can.$), a price which was required to make significant quantities of coal bed methane available[15].

14.0 Discussion

Westcoast Energy forecasts domestic natural gas requirements for power generation will be 29 PJ by 1996 and export requirements will be 48 PJ. These estimates compare favourably with independent estimates resulting from a survey of electric utilities in the area. West coast Energy also forecasts a natural gas demand of an additional 273 PJ for the rest of the domestic market and 301 PJ for export to serve non-generation customers.

Natural gas prices will affect the availability of resources to serve the above loads, thereby producing a potential time lag between higher prices and the availability of additional resources. Natural gas price forecasting is difficult and has been thrown into disrepute by the erroneously high forecasts of the early 1980s. These forecasts failed to consider basic processes which affect supply and cost -

1. Proven reserves expand as prices increase.
2. Coal bed methane exploration and development is being subsidized in the U.S., increasing the supply of methane which is substituted for natural gas.
3. The present recession has decreased the demand for natural gas.
4. A mild winter has reduced the demand for natural gas over the high demand period.
5. The cost of extraction has fallen as productivity in manufacturing which supplies the natural gas industry has increased, thereby reducing the cost of machinery and consummables.
6. Improvements in exploration and production techniques have increased the success ratio for new wells.
7. Deregulation has improved efficiency in the market place.

Therefore, uncertainty is the key word in evaluating the course of future natural gas price increases. The recession and mild winter will have a short term impact, coal bed methane could have an impact over the longer term if the subsidy is renewed at the end of 1992. The remaining processes are longer term, but their impact has already been absorbed. Natural gas prices will start increasing soon with the end of the recession and a colder winter. The increases are expected to be caused mainly by increases in the wellhead price because most new resources will come from more remote, deeper and/or tighter reservoirs. In the literature reviewed for this report, the wellhead price increases in real terms ranged from 3.3%/a (from a base price of $1.37 for 1991 in

1990 Can.$/GJ) in the Confer Report to 10.3%/a (from a base price of $1.88 for 1991 in 1990 Can.$) in a report by Enron in the U.S. In general, the B.C. studies were in the 3%/a range and the American studies agreed with the National Energy Board study which forecast a real price increase of 5.7%/a. EPRI forecasts that there are approximately 33 years of natural gas resources in the U.S. at a wellhead price of less than $3.25/GJ (1990 Can.$) based on an average rate of production of 18 Tcf/a (510 Gm^3/a) which is expected to be exceeded in about the year 2000 (Enron study). This indicates that $3.25/GJ is the upper limit for the natural gas price in the U.S. over that period and that the price in B.C. would be considerably lower to allow for additional transportation costs into the U.S. market. However, it is also evident that it would require significant increases in the wellhead price of natural gas to encourage the development of all of these resources, but the increases are within the range of the above forecasts.

An Examination of a number of price forecasts (Table 2 in Summary) indicates a wide range - from 3.3%/a to 10.3%/a (real). The two lowest forecasts are from B.C. In addition, wellhead forecasts are tempered by forecasts of no real increases (taxes excluded) in the processing and delivery of natural gas. The proportion of wellhead price to processing and delivery cost for firm natural gas for large industrial customers is approximately 60:40 at present. Therefore, the real price increases in delivered natural gas on the Lower Mainland is expected to be 2.0-6.2%/a. Natural gas price escalation will begin slowly at a fraction of a percent per annum, but increase in the mid-1990s as new markets are introduced in the eastern U.S. and as utilities commence repowering and new plant operation with combustion turbines.

To measure the impact of fuel price escalation on the cost of electricity, a sensitivity study was conducted by varying the rate of escalation of fuel prices, the escalation period and the capacity factor (Table 14-1). Fuel prices were assumed to escalate at a constant rate over the period. Unit energy costs were calculated for a 207 MW simple cycle combustion turbine plant and for a 468 MW combined cycle plant. The costs were based on cost and efficiency estimates supplied by GE Canada for a simple cycle plant consisting of LM6000s and for a 207FA combined cycle plant with reheat. The unit energy costs ranged from 3.4 cents/kW.h for a combined cycle plant at 80 percent capacity factor, a short fuel price escalation period and a low rate of fuel price escalation to 9.1 cents/kW.h for a combined cycle plant with a 20 percent capacity factor, a long fuel price escalation period and a high rate of fuel price escalation.

Although it is forecast that there should be no significant change in the quantity of interruptible natural gas available, the nature of power generation is going through changes which will make this estimate less important. Firm natural gas will be required both to

Table 14 -1 Sensitivity Study of Delivered Fuel Price Increases

Unit Energy Costs (Cents/kW.h)

Levelized Fuel Price ($/GJ)[1]	Capacity Factor (%) 20	40	60	80
Simple Cycle:				
2.62[2]	6.80	4.56	3.81	3.44
2.75[3]	6.46	4.45	3.78	3.44
3.81[4]	7.85	5.62	4.87	4.50
4.61[5]	8.11	6.10	5.43	5.09
Combined Cycle:				
2.62[2]	8.38	5.09	3.99	3.44
2.75[3]	7.80	4.84	3.85	3.36
3.81[4]	9.20	5.90	4.80	4.25
4.61[5]	9.07	6.11	5.12	4.63

1. Fuel prices assume a base delivered price of $2.22 (1990 Can.$/GJ) in 1991.

2. Assumes a fuel price escalation of 2.0%/a (real) for 20 years and a 20 year contract.

3. Assumes a fuel price escalation of 2.0%/a (real) for 30 years and a 30 year plant life.

4. Assumes a fuel price escalation of 6.2%/a (real) for 20 years and a 20 year contract.

5. Assumes a fuel price escalation of 6.2%/a (real) for 30 years and a 30 year plant life.

meet electricity demand because of the increased reliance on combustion turbine plants and to base load the plants of IPPs and self-generators to meet their financial requirements . The result will be an increasing emphasis on firm natural gas contracts at higher prices. The effective annual increase in wellhead price over 20 years would range from 4-8% allowing for the transition from valley gas to firm gas.

These fuel supply uncertainties dictate the need for planning when installing new natural gas-fired generation. The planning requires input from resource planners, fuel suppliers, pipeline operations, electric utility operators, system planners, contract lawyers and possibly IPPs. During operations, close contact between the pipeline and utility operations personnel is essential, particularly where combustion turbines are involved.

In Resource Planning, planners must evaluate options such as undertaking significant repairs at the Burrard Thermal Plant, repowering, the installation of new natural gas-fired facilities or purchases from IPPs with natural gas-fired generating facilities. These evaluations try to identify the most economical and reliable set of resources. The planners must examine not only the cost of the generation, but the cost and risks related to fuel supply and the cost and availability of backup. In assessing the risks related to fuel supply, the Resource Planners must examine not only the reserves of fuel, but also the deliverability which for natural gas is particularly important because the utility does not maintain a supply of natural gas on site. The cost of the back-up fuel supply must be included in the operating costs of the plant. In short, an integrated approach is required in assessing proposed natural gas-fired projects. Strategies for supply, transportation and storage of fuel and dispatch of generating units must be worked out at the planning stage to estimate the cost of natural gas-fired generation.

In Electrical Operations, the operators are concerned with reliability, dynamic response, seasonal operations, environmental compliance, fuel inventory and coordination issues. Unlike electric utilities, the gas industry relies on a small amount of storage and curtailment to provide reliable service in the other sectors. Unfortunately for utilities, it is the utility and industrial boilers which commonly use non-firm natural gas that are traditionally curtailed. Therefore, unless the natural gas industry develops other alternatives to curtailment, the simultaneous disappearance of the generating capacity surplus and the gas supply "bubble" will create severe risks for future natural gas-fired power generation. Coordination between the natural gas supplier and the electric utility will be increasingly important as more combustion turbines come on line. Combustion turbines respond quickly to load changes producing equally rapid swings in natural gas demand. Natural gas suppliers may have severe problems in meeting these rapid swings. This requires more coordination between the operating personnel of the gas supplier and the utility. Operators must also examine the seasonal deliverability of natural gas. Greater utility gas-fired generation requires additional gas storage and more filling of that storage in the spring and fall as well as in the summer. For base load combustion turbine plants, long term fuel contracts are required to ensure that gas production and delivery facilities are in place. With combustion turbines for peaking duty, the fuel price is less important, but dependabliity of fuel supply is particularly important. For both peaking and base load units the issue of back-up fuel is critical and a supply will have to remain on hand. It is important to note that fuel switching capability could be compromised by environmental compliance regulations which could reduce reliability and increase natural gas price volatility.

In System Planning, the engineers must examine the implications of the new generating facilities on the system and suggest modifications in size, location, equipment or operating regime which could strengthen the transmission system.

Natural gas is the fuel of choice for environmental reasons. In Environmental Resources, the potential for switching from natural gas to oil and its environmental implications must be examined. That option is no longer available at Burrard Thermal Plant and generating facilities elsewhere may have similar restrictions. The demand for natural gas created partly by environmental regulations could have the impact of significantly increasing the price of natural gas. Eliminating the fuel oil option could adversely affect fuel supply reliability. It is important to note that new natural gas-fired units may require high cost selective catalytic reduction (SCR) to comply with environmental regulations.

In general, the natural gas industry in the U.S. and Canada has little experience in dealing with utilities. In 1988, 88 percent of natural gas-fired electricity generation was concentrated in only 6 states in the U.S.[12]. The natural gas industry is not experienced with increasing its supply quickly to meet growing demand. In contrast, the electric utility industry has built up a capacity margin and coordination among utilities through NERC. There is no analogous concern for reliability in the natural gas industry and less integration among the players on the supply side - production and processing, transmission and distribution.

15.0 Conclusions

The utility industry should not be deterred by the problems identified in this report. Natural gas-fired generation provides an important option for meeting future demand. However, the potential problems must be addressed and close cooperation is required between the electric utility, natural gas utility and the suppliers of natural gas. Electric and natural gas utilities should cooperate in the regulatory arena for the interests of both industries. Action should be taken at an early stage to develop a working group among all of the participants from the wellhead to the electric utility generator. The natural gas industry should be encouraged to examine methods of load management similar to NERC among electric utilities. Natural gas-fired generation must be examined closely to ensure that all costs are being included and the desired reliability is met. The natural gas industry should re-examine its rate structure and storage requirements to ensure that they meet the needs of an important customer, the utility industry. It is the utility industry that is expected to produce most of the growth in natural gas demand over the next 20 years. The development of long term contracts has begun in Canada, but it is not common in the U.S. Long term contracts are expected to become more important in both the U.S. and Canada in ensuring revenues for the natural gas industry and a supply of natural gas for the electric utility. Contracts, which are developed, should meet the electric utility's needs for unit dispatching.

The natural gas "bubble" has burst, but with a whimper rather than an explosion. The evidence for the "bursting bubble" can be seen in several areas. There is a shortage of supplies of natural gas in many places in the U.S. and Canada during periods of peak demand which causes a run-up in price. For example, although summer natural gas wellhead spot sales have been as low as the \$0.80/Mcf (U.S.\$) or \$32.10/10^3m^3 (Can.\$) range, natural gas futures for delivery in January, 1992 reached wellhead prices as high as \$2.20/Mcf (U.S.\$)or \$88.28/10^3m^3 (Can.\$)[20]. More recently natural gas prices plummeted because of three short term conditions:

1. The U.S. has been subsidizing coal bed methane exploration which has brought a significant amount of this gas onto the market in the southwestern U.S. These resources deplete quickly and the subsidy is scheduled to come off any discoveries made after 31 December, 1992.

2. This winter has been particularly mild in western Canada which has reduced the demand for natural gas.

3. The present recession has also reduced the demand for natural gas.

In the Lower Mainland, natural gas must be withdrawn from liquid storage on cold days during the spring and fall as well as in the winter. The export pipeline at Huntingdon is at capacity for short periods on many days from late fall to early spring. The commitment of more utilities to natural gas-fired generation will certainly aggrevate the "burst bubble" situation unless there are increases in natural gas prices (through commitments to firm natural gas rather than interruptible natural gas or, at least in part, through the purchase of new reserves from more remote sites) or subsidies for substitutes such as coal bed methane.

Almost all of the conventional natural gas-fired thermal generation in the U.S. and Canada will be retired within 20 years. Thus, decisions on life extensions, repowering or new plant construction will be required. Most of the new plants and repowering will likely involve the installation of combustion turbines which will alter the demand for natural gas and the nature of the fuel switching buffer, changing it from No.6 to No. 2 fuel oil. The higher cost for No.2 fuel oil would raise the upper limit on natural gas price before substitution is made.

The uncertainty over the rate of natural gas price escalation indicates the need to approach flow-through costs for fuel among IPPs and self-generators with extreme caution. If B.C. Hydro is to absorb any of the risk in this area, it should be based on a predetermined formula which shares that risk, otherwise there is little advantage in purchasing from IPPs and self-generators. If they are guaranteed a market and the principal uncertainty in their operations, fuel price, they will be almost risk-free.

16.0 Recommendations

1. Develop a comprehensive strategy or contingency plan for dealing with increased electricity demand or a reduction in expected resources from IPPs, self-generation or demand side management.

2. Examine the collective environmental impacts of proposed thermal projects in southwest B.C. and northwest Washington and the effect of these projects on the operation of the Burrard Thermal Plant.

3. Coordinate environmental programs on air emissions with utilities, self-generators, IPPs and regulatory bodies in Washington state as well as in B.C.

4. Examine the potential for emissions trading with other industries to optimize the environmental improvements from expenditures.

5. Examine and coordinate operating procedures with natural gas pipeline operators; determine where pipeline operating procedures can be modified to increase reliability, reduce or eliminate curtailments and reduce the impacts of pressure fluctuations during combustion turbine start-up and shut-down.

6. Monitor the need for securing natural gas supplies through purchase of shut-in natural gas, partnerships or long term contracts. Carefully examine any price re-opening provisions in long term contracts.

7. Re-evaluate the advisability of accepting the fuel price risk from IPPs or self-generators in terms of the cost/benefit of the project to B.C. Hydro and to the IPP or self-generator. Would the cost/benefit improve if B.C. Hydro was to develop these projects on its own?

8. Encourage the development of underground natural gas storage near the load centre (in the Fraser Valley - B.C. or Washington, or on Vancouver Island) if it can be developed in a safe and environmentally sound manner.

9. Cooperate with the natural gas industry to promote regulatory conditions which are of mutual benefit.

10. Examine the availability of surplus combustion turbine manufacturing capacity and the likelihood of the utility and airline industries making large orders for combustion turbines at the same time.

11. Determine the effect of new proposed thermal facilities in the U.S. Pacific Northwest on the value of Columbia River DSBs.

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